EXHIBIT A

Attached to Conservation Groups'
May 27, 2011 Public Comment Letter
Submitted in EIB 11-01 (R) and EIB 11-02 (R)

San Juan Citizens Alliance

New Mexico Chapter
108 North Behrend, Suite I
Farmington, NM 87401
Ph: 505-325-6724
New Mexico Office Cell: 505-360-8994

May 3, 2011

Secretary F. David Martin
New Mexico Environment Department
Harold Runnels Building
1190 St. Francis Drive (87505)
P.O. 5469
Santa Fe, NM 87502
Phone (505) 827-2855

Re: New Mexico Environment Department, Air Quality Bureau May 3, 2011 Public Meeting in Farmington on the proposed Regional Haze state implementation plan revisions and proposed revisions to the good neighbor provisions of New Mexico's infrastructure state implementation plan. The New Mexico revisions include a determination of Best Available Retrofit Technology for San Juan Generating Station.

Dear Mr. Martin,

San Juan Citizens Alliance (SJCA) submits several documents to be entered into the record at the New Mexico Environment Department (NMED), Air Quality Bureau (AQB) May 3, 2011 Public Meeting in Farmington on the proposed Regional Haze state implementation plan (SIP) revisions and proposed revisions to the good neighbor provisions of New Mexico's infrastructure state implementation plan. The New Mexico revisions include a determination of Best Available Retrofit Technology (BART) for the Public Service Company of New Mexico (PNM) San Juan Generating Station (SJGS). The following documents pertain to the State of New Mexico's attempt to portray Selective Non-Catalytic Reduction (SNCR) as BART for San Juan Generating Station. NMED submitted a March 21, 2011 letter to Dr Alfredo Armendariz, Regional Administrator, U.S. Environmental Protection Agency Region 6 concerning the proposed Federal Implementation Plan (FIP) (Docket No. EPA-R06-OAR-2010-0846) for San Juan Generating Station asserting authority to present SIPs under the Clean Air Act.

SJCA and other organizations (SJCA, et al, April 4, 2011 EPA Docket No. EPA-R06-OAR-2010-0846) timely submitted comments to the EPA on the San Juan Generating Station FIP. These comments were in response to the EPA Proposed Rule under 40 CFR Part 52, Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination (Federal Register/Vol. 76, No. 3/Wednesday, January 5, 2011/Proposed Rules). **A copy of the Federal Register Notice, January 5, 2011, is attached as Exhibit 1 to this letter.** The primary point of the SJCA, et al, comments on the FIP was to support Selective Catalytic Reduction (SCR) as BART under the Clean Air Act Regional Haze Program for the SJGS. **A copy of the SJCA, et al, April 4, 2001 comments to EPA on EPA Docket No. EPA-R06-OAR-2010-0846 are attached as Exhibit 2.**

Comments on the BART analysis for San Juan Generating Station were also submitted by Dr. Ranajit (Ron) Sahu, Ph. D on April 4, 2011. **A copy of Dr. Sahu's April 4, 2001 comments to EPA on EPA Docket No. EPA-R06-OAR-2010-0846 are attached as Exhibit 3.** Of significance in Dr. Sahu's comments is his opinion that SCR is the proper choice for Nitrogen Oxide (NOx) reduction technology as BART and that proper BART level should not exceed 0.035 lb/MMBtu on a 30-day rolling average.

The U.S. Department of the Interior National Park Service (NPS) Air Resources Division, in consultation with the U.S. Fish and Wildlife Service (FWS) submitted a March 31, 2011 letter to Mary Uhl, NMED/AQB concerning the State's BART Determination for NOx emissions for San Juan Generating Station dated February 28, 2011. The NPS states the following:

> Since EPA has previously proposed a Federal NOx BART determination for SJGS, we understand that the federal proposal supersedes the state proposal. We disagree with New Mexico's proposal that Selective Non-Catalytic Reduction technology is sufficient and continue to assert that Selective Catalytic Reduction is BART for SJGS.

A copy of the NPS/FWS March 31, 2011 letter to Mary Uhl at NMED/AQB and Guy Donaldson at EPA Region 6 is included as Exhibit 4.

Dr. Sahu has prepared a May 1, 2011 Brief Critique of San Juan Units 1-4 Proposed NOx BART Proposal for NOx Reduction Using Selective Non-Catalytic Reduction (SNCR) with the following 10 points:

1. PNM and the state of New Mexico have provided additional proposals and analyses for NOx BART after the date of the EPA BART proposal. See http://www.nmenv.state.nm.us/aqb/reghaz/Regional-Haze_index.html. In these most recent proposals, which are up for adoption before the New Mexico Environmental Improvement Board (EIB), the state of New Mexico is urging the EIB to adopt a NOx BART level of 0.23 lb/MMBtu for Units 1-4, using a NOx reduction technology called

Selective Non-Catalytic Reduction (SNCR). The 0.23 lb/MMBtu level is a far less stringent level of control than EPA's already-lenient proposal of 0.05 lb/MMBtu.[1]

2. All emissions levels in this discussion are on a 30-day rolling average basis. These 4 units are all base-loaded, so the load changes are not frequent or dramatic.

3. As discussed in great detail in the April 4, 2011 comments by Ron Sahu on the SJGS Section 110 FIP, the current level of NOx emissions from Units 1-4 are around 0.29 lb/MMBtu. Each unit is required to meet a limit of 0.30 lb/MMBtu based on a prior Consent Decree with the state of New Mexico and several environmental organizations. San Juan is meeting the Consent Decree requirements by keeping its NOx level slightly below the Consent Decree level.

4. There are reasons to believe that even without any additional controls, the NOx emissions levels from each of these Units could be lower than 0.29 lb/MMBtu – likely even as low as 0.28 or 0.27 lb/MMBtu by using the latest generation low NOx burners, using optimized over-fire air strategies and by using adaptive or neural-network techniques. Nonetheless, let us assume that the boiler-out NOx emissions stay at 0.29 lb/MMBtu.

5. The San Juan proposal of 0.23 lb/MMBtu NOx using SNCR effectively represents a NOx reduction percentage of 20.7% when compared to the current level of 0.29 lb/MMBtu, at each unit. This is a paltry level of emissions reduction, and likely to be even smaller, if San Juan chooses to (and could) further reduce NOx from each of these Units without any further control, as suggested earlier.

6. SNCR is not a top NOx reduction technology from utility boilers such as San Juan. While it has been applied in some situations in the past, there is no question that, operationally, even under the best of circumstances, NOx reductions expected from SNCR (generally in the range of 20-70%) are far smaller than reductions possible using the top technology, of Selective Catalytic Reduction (SCR), which is 90% or greater.

7. And, in this instance, San Juan appears to be seeking approval to get only a 20% reduction from SNCR, which is at the lower end of even SNCR's NOx reduction capability. And, with this minimal NOx reduction, there is likely to be far greater ammonia emissions. Ammonia is used as the agent for NOx reduction in both SNCR and SCR. But, while the excess ammonia in the SCR system is typically around 2 ppm, the excess ammonia (which is emitted to the atmosphere) is around 10 ppm or greater.

8. The only reason that San Juan is pushing for SNCR as opposed to SCR is cost. And, as discussed in the April 4, 2011 Sahu comments, the SCR cost analysis presented by San Juan is flawed, thereby inflating SCR costs.

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[1] The reasons why even the EPA's 0.05 lb/MMBtu level of NOx for these 4 Units is lenient are discussed more fully in my comments provided to the EPA proposal in a report dated April 4, 2011.

9. There is no doubt that SNCR is cheaper to install and operate than SCR. But, the NOx reduction benefits from SCR are far greater than SNCR.

10. In rejecting SCR and proposing SNCR, San Juan relies on inaccurate cost data to inflate the cost of installing SCR and it improperly addresses cost impacts on New Mexico electricity customers (not a BART factor), without any consideration of the benefits of reduced NOx pollution on the very same customers and others who are affected by emissions from this plant. Thus, San Juan seems to believe that adverse health impacts have no cost penalties.

SJCA concurs with Dr. Sahu's critique of the State of New Mexico's SIP for the SJGS BART determination and asserts that SNCR is not BART. The SNCR proposal would remove only 20% of the NOx from the 18th highest NOx emitting coal plant in the country. This is unacceptable when compared to the 90-95% NOx removal expected from SCR. SJCA emphasizes that the EPA has the authority under the Clean Air Act to insure that BART is implemented accurately at SJGS. Any attempt by New Mexico to portray BART as SNCR must be disapproved. SJCA also notes that the consent decree deadline for issuance of a final Interstate Transport FIP or SIP is June 21, 2011. SJCA objects to any extension of this consent decree deadline for PNM.

Thank you for the opportunity to submit this letter.

Sincerely,

Mike Eisenfeld

Mike Eisenfeld
New Mexico Energy Coordinator
San Juan Citizens Alliance
108 North Behrend, Suite I
Farmington, New Mexico 87401
office 505 325-6724
cell 505 360-8994
meisenfeld@frontier.net

EXHIBIT 1

Federal Register Notice, January 5, 2011

Consistent with the above statutory and regulatory framework, the FAA has adopted policy to establish the standards for which the FAA identifies "obstructions" and "hazards" in the navigable airspace in furtherance of its responsibilities to manage the navigable airspace safely and efficiently. *See* 14 CFR part 77, and FAA Order 7400.2, Procedures for Handling Airspace Matters. The FAA issues a determination advising whether the structure would be a hazard to air navigation. The FAA may condition its determination of no hazard with the structure appropriately being marked and lighted, as specified in the determination. FAA criteria for marking and lighting of tall structures are found in Advisory Circular No. 70/7460–1, Obstruction Marking and Lighting.

Unless within the vicinity of an airport,[1] proponents of new structures or alterations of existing structures must file notice with the FAA for "any construction or alteration of more than 200 feet in height above the ground level at its site." 14 CFR 77.13(a)(1). Consequently, as the FAA does not study these structures there is no FAA determination that would specify the marking of these structures.

Background

The emphasis to discover sources of renewable energy in the United States has prompted individuals and companies to explore all means of energy generation. Wind energy, converted into electrical energy by wind turbines, is widely pursued as a viable alternative. In order to determine if a site meets requirements to construct a wind turbine or wind farm, companies erect METs. These towers are used to gather wind data necessary for site evaluation and development of wind energy projects. The data generally is gathered over a year to ascertain if the targeted area represents a potential location for the installation of wind turbines.

Requirements to file notice under part 77 generally do not apply to structures at heights lower than 200 feet AGL unless close to an airport environment. Therefore, the FAA does not have a database of MET locations, nor does it conduct an aeronautical study to determine whether the particular structure would be hazardous to aviation. These towers are often installed in remote or rural areas, just under 200 feet above ground level (AGL), usually at 198 feet or less. These structures are portable, erected in a matter of hours, installed with guyed wires and constructed from a galvanized material often making them difficult to see in certain atmospheric conditions.

While the METs described above are not subject to the provisions of part 77 and therefore, the FAA does not conduct aeronautical studies to determine whether these structures are obstructions and adversely impact air navigation, the FAA does acknowledge that these towers under certain conditions may be difficult to see by low-level agricultural flights operating under visual flight rules. The color, portability of these towers, their placement in rural and remote areas, and their ability to be erected quickly are factors that pilots should be aware of when conducting operations in these areas.

The FAA has received complaints and inquiries from agricultural operations in remote or rural areas regarding the safety impacts of these towers on low-level agricultural operations. In addition, representatives from the National Agricultural Aviation Association (NAAA) met with the FAA on November 16, 2010 to discuss safety specific concerns of the aerial application industry. The NAAA suggested safety guidelines and marking and lighting criteria in order to reduce the risks for aerial applications. A copy of the material provided by NAAA has been placed in the docket.

Proposed Guidance

The FAA is considering revising AC No. 70/7460–1, Obstruction Marking and Lighting, to include guidance for the voluntary marking of METs that are less than 200 feet AGL. The FAA recognizes the need to enhance the conspicuity of these METs, particularly for low-level agricultural operations and seeks public comment on the guidance provided below.

The FAA recommends that the towers be painted in accordance to the marking criteria contained in Chapter 3, paragraphs 30–33 of AC No. 70/7460–1. In particular, we reference paragraph 33(d), which discusses alternate bands of aviation orange and white paint for skeletal framework of storage tanks and similar structures, and towers that have cables attached. The FAA also recommends spherical and/or flag markers be used in addition to aviation orange and white paint when additional conspicuity is necessary. Markers should be installed and displayed according to the existing standards contained in Chapter 3, paragraph 34 of AC No. 70/70460–1.

The FAA is also considering recommending high visibility sleeves on the outer guy wires of these METs. While the current Obstruction Marking and Lighting Advisory Circular does not contain such guidance for high visibility sleeves, the FAA specifically seeks comments on this recommendation.

The FAA anticipates that a uniform and consistent scheme for voluntarily marking these METs would enhance safety by making these towers more readily identifiable for agricultural operations.

Issued in Washington, DC, on December 29, 2010.

Edith V. Parish,

Manager, Airspace, Regulations and ATC Procedures Group.

[FR Doc. 2010–33310 Filed 1–4–11; 8:45 am]

BILLING CODE 4910–13–P

[1] 14 CFR 77.13(a), paragraphs (2), (3), (4) and (5) are not relevant to this issue.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2010–0846; FRL–9246–8]

Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to disapprove a portion of the State Implementation Plan (SIP) revision submitted by the State of New Mexico for the purpose of addressing the "good neighbor" requirements of section 110(a)(2)(D)(i) of the Clean Air Act (CAA or Act) for the 1997 8-hour ozone National Ambient Air Quality Standards (NAAQS or standards) and the 1997 fine particulate matter ($PM_{2.5}$) NAAQS. The SIP revision addresses the requirement that New Mexico's SIP must have adequate provisions to prohibit emissions from adversely affecting another state's air quality through interstate transport. In this action, EPA is proposing to disapprove the New Mexico Interstate Transport SIP provisions that address the requirement of section 110(a)(2)(D)(i)(II) that emissions from New Mexico sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. In this action, EPA is also proposing to promulgate a Federal Implementation Plan (FIP) to prevent emissions from New Mexico sources from interfering with other states' measures to protect

visibility, and to implement nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emission limits necessary at one source to prevent such interference. In addition, EPA is proposing sulfuric acid (H_2SO_4) and ammonia (NH_3) hourly emission limits at the same source, to minimize the contribution of these compounds to visibility impairment. EPA is proposing monitoring, recordkeeping and reporting requirements to ensure compliance with such emission limitations. EPA also proposes that compliance with the emission limits be within three (3) years of the effective date of our final rule. Furthermore, EPA is proposing the FIP to address the requirement for best available retrofit technology (BART) for NO_X for this source. This action is being taken under section 110 and part C of the CAA.

DATES: *Comments.* Comments must be received on or before March 7, 2011.

Public Hearing. EPA intends to hold a public hearing in Farmington, New Mexico to accept oral and written comments on the proposed rulemaking. EPA will provide notice and additional details at least 30 days prior to the hearing in the **Federal Register**.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2010–0846, by one of the following methods:

• *Federal e-Rulemaking Portal: http://www.regulations.gov.*

• Follow the online instructions for submitting comments.

• *EPA Region 6 "Contact Us" Web site: http://epa.gov/region6/r6coment.htm.* Please click on "6PD (Multimedia)" and select "Air" before submitting comments.

• *E-mail:* Mr. Guy Donaldson at *donaldson.guy@epa.gov.* Please also send a copy by e-mail to the person listed in the **FOR FURTHER INFORMATION CONTACT** section below.

• *Fax:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), at fax number 214–665–7263.

• *Mail:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733.

• *Hand or Courier Delivery:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. Such deliveries are accepted only between the hours of 8 a.m. and 4 p.m. weekdays, and not on legal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket No. EPA–R06–OAR–2010–0846. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733. The file will be made available by appointment for public inspection in the Region 6 FOIA Review Room between the hours of 8:30 a.m. and 4:30 p.m. weekdays except for legal holidays. Contact the person listed in the **FOR FURTHER INFORMATION CONTACT** paragraph below or Mr. Bill Deese at 214–665–7253 to make an appointment. If possible, please make the appointment at least two working days in advance of your visit. There will be a 15 cent per page fee for making photocopies of documents. On the day of the visit, please check in at the EPA Region 6 reception area at 1445 Ross Avenue, Suite 700, Dallas, Texas.

The state submittal is also available for public inspection during official business hours, by appointment, at the New Mexico Environment Department, Air Quality Bureau, 1301 Siler Road, Building B, Santa Fe, New Mexico 87507.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, Air Planning Section (6PD–L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733, telephone (214) 665–7186, fax number (214) 665–7263; e-mail address *kordzi.joe@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document wherever "we," "us," or "our" is used, we mean the EPA.

Outline

I. Overview of Proposed Action

We are proposing to disapprove a portion of the SIP revision submitted by the State of New Mexico for the purpose of addressing the "good neighbor" provisions of the CAA section 110(a)(2)(D)(i) with respect to visibility for the 1997 8-hour ozone NAAQS and the $PM_{2.5}$ NAAQS. As a result of the proposed disapproval, we are also proposing a FIP to address the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility to ensure that emissions from New Mexico sources do not interfere with the visibility programs of other states. We are proposing to find that New Mexico sources, other than one, are sufficiently controlled to eliminate interference with the visibility programs of other states, and for the one remaining source we are proposing to impose specific emissions limits that will eliminate such interstate interference. We are simultaneously evaluating whether the source at issue meets certain other related requirements under the Regional Haze (RH) program. As a result of this evaluation, we are likewise proposing to find that the proposed controls for the source at issue will address the NO_X BART requirements of the RH program. In this action, we are not addressing whether the state has met other requirements of the RH program and will address those requirements in later actions.

Section 110(a)(2)(D)(i)(II) of the Act requires that states have a SIP, or submit a SIP revision, containing provisions "prohibiting any source or other type of emission activity within the state from emitting any air pollutant in amounts which will * * * interfere with measures required to be included in the applicable implementation plan for any other State under part C [of the CAA] to protect visibility."

Because of the impacts on visibility from the interstate transport of pollutants, we interpret the "good neighbor" provisions of section 110 of the Act described above as requiring states to include in their SIPs measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states. New Mexico submitted a SIP to address these requirements in September 2007. In this action, we are proposing to disapprove the New Mexico SIP submission as not meeting the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility. The SIP submission made by the state anticipated the timely submission of a substantive RH SIP submission as the means of meeting the requirements of section 110(a)(2)(D)(i)(II). New Mexico has yet to submit such a RH SIP. In addition, the state has not revised its submission to address the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility by any alternative means.

By December 17, 2007, each State with one or more Class I Federal areas was also required to submit a RH SIP that included goals that provide for reasonable progress towards achieving natural visibility conditions. 40 CFR 51.308(d)(1). We previously found that New Mexico had failed to submit a complete RH SIP by December 17, 2007. 74 FR 2392 (January 15, 2009). This finding started a two year clock for the promulgation of a RH FIP by EPA or the approval of a complete RH SIP from New Mexico. CAA § 110(c)(1).

To address the above concerns, we are also proposing to promulgate a FIP that ensures that emissions from New Mexico sources do not interfere with other states' measures to protect visibility in accordance with section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS, and also to address the requirements under the RH program for BART by imposing limits for NO_X for the San Juan Generating Station (SJGS).[1] This FIP will limit the emissions of SO_2 and NO_X from the SJGS. Together, the reduction in NO_X from our proposed NO_X BART determination, and the proposed SO_2 emission limits to establish federal enforceability of current SO_2 levels will serve to ensure there are enforceable mechanisms in place to prohibit New Mexico NO_X and SO_2 emissions from interfering with efforts to protect visibility in other states pursuant to the requirements of section 110(a)(2)(D)(i)(II) of the CAA. NO_X and SO_2 are significant contributors to visibility impairment in and around New Mexico. As the Four Corners Task Force notes,[2] "[r]eduction of NO_X is particularly important to improve visibility at Mesa Verde National Park, which is 43 km away from SJGS. * * * [V]isibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate)." For NO_X emissions, we are proposing to require the SJGS to meet an emission limit of 0.05 pounds per million British Thermal Units (lb/MMBtu) at Units 1, 2, 3, and 4, representing an approximately 83% reduction from the SJGS's baseline NO_X emissions. This NO_X limit is achievable by installing and operating Selective Catalytic Reduction (SCR). For SO_2, we are proposing to require the SJGS to meet an emission limit of 0.15 lb/MMBtu. Both of these emission limits would be measured on the basis of a 30-day rolling average. We are also proposing hourly average emission limits for sulfuric acid (H_2SO_4) and ammonia (NH_3) for the SJGS, to minimize the contribution of these compounds to visibility impairment of Class I areas.

Furthermore, we propose that compliance with the emission limits be within three (3) years of the effective date of our final rule. Additionally, we are proposing monitoring, recordkeeping, and reporting requirements to ensure compliance with emission limitations. Please see Section IV (Proposed Action) and the proposed regulation language at the end of this **Federal Register** action for more information.

II. Background

A. SIP and FIP Background

The CAA requires each state to develop a plan that provides for the implementation, maintenance, and enforcement of the NAAQS. CAA section 110(a). We establish NAAQS under section 109 of the CAA. Currently, the NAAQS address six (6) criteria pollutants: Carbon monoxide, nitrogen dioxide, ozone, lead, particulate matter, and sulfur dioxide. The plan developed by a state is referred to as the SIP. The content of the SIP is specified in section 110 of the CAA, other provisions of the CAA, and applicable regulations. A primary purpose of the SIP is to provide the air pollution regulations, control strategies, and other means or techniques developed by the state to ensure that the ambient air within that state meets the NAAQS. However, another important aspect of the SIP is to ensure that emissions from within the state do not have certain prohibited impacts upon the ambient air in other states through the interstate transport of pollutants. CAA section 110(a)(2)(D)(i). States are required to update or revise SIPs under certain circumstances. *See* CAA section 110(a)(1). One such circumstance is our promulgation of a new or revised NAAQS. *Id.* Each state must submit these revisions to us for approval and incorporation into the federally-enforceable SIP.

If a State fails to make a required SIP submittal or if we find that the State's submittal is incomplete or unapprovable, then we must promulgate a FIP to fill this regulatory gap. CAA section 110(c)(1). As discussed elsewhere in this notice, we have made findings related to New Mexico SIP revisions needed to address interstate transport and the requirement that emissions from New Mexico sources do not interfere with measures required in the SIP of any other state to protect visibility, pursuant to section 110(a)(2)(D)(i)(II) of the CAA. We are proposing a FIP to address the deficiencies in the New Mexico Interstate Transport SIP.

[1] Unless otherwise specified, when we say the "San Juan Generating Station," or "SJGS," we mean units 1, 2, 3, and 4, inclusive.

[2] Power Plants Section, Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, *available at: http://www.nmenv.state.nm.us/aqb/4C/Docs/4CAQTF_Report_FINAL_PowerPlants.pdf.*

B. Statutory and Regulatory Framework Addressing Interstate Transport and Visibility

1. The 1997 NAAQS for Ozone and $PM_{2.5}$ and CAA 110(a)(2)(D)(i)

On July 18, 1997, we promulgated new NAAQS for 8-hour ozone and for $PM_{2.5}$. 62 FR 38652. Section 110(a)(1) of the CAA requires states to submit SIPs to address a new or revised NAAQS within 3 years after promulgation of such standards, or within such shorter period as we may prescribe. Section 110(a)(2) of the CAA lists the elements that such new SIPs must address, as applicable, including section 110(a)(2)(D)(i), which pertains to the interstate transport of certain emissions.

On April 25, 2005, we published a "Finding of Failure to Submit SIPs for Interstate Transport for the 8-hour Ozone and $PM_{2.5}$ NAAQS." 70 FR 21147. This included a finding that New Mexico and other states had failed to submit SIPs for interstate transport of air pollution affecting visibility, and started a 2-year clock for the promulgation of a FIP by us, unless a State made a submission to meet the requirements of section 110(a)(2)(D)(i) and we approved the submission. *Id.*

On August 15, 2006, we issued our "Guidance for State Implementation Plan (SIP) Submission to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards" (2006 Guidance). We developed the 2006 Guidance to make recommendations to states for making submissions to meet the requirements of section 110(a)(2)(D)(i) for the 1997 8-hour ozone standards and the 1997 $PM_{2.5}$ standards.

As identified in the 2006 Guidance, the "good neighbor" provisions in section 110(a)(2)(D)(i) of the CAA require each state to submit a SIP that prohibits emissions that adversely affect another state in the ways contemplated in the statute. Section 110(a)(2)(D)(i) contains four distinct requirements related to the impacts of interstate transport. The SIP must prevent sources in the state from emitting pollutants in amounts which will: (1) Contribute significantly to nonattainment of the NAAQS in other states; (2) interfere with maintenance of the NAAQS in other states; (3) interfere with provisions to prevent significant deterioration of air quality in other states; or (4) interfere with efforts to protect visibility in other states.

The 2006 Guidance stated that states may make a simple SIP submission confirming that it was not possible at that time to assess whether there is any interference with measures in the applicable SIP for another state designed to "protect visibility" for the 8-hour ozone and $PM_{2.5}$ NAAQS until RH SIPs are submitted and approved. RH SIPs were required to be submitted by December 17, 2007. *See* 74 FR 2392 (January 15, 2009); *see also* discussion *infra* section II.B.2.

On September 17, 2007 we received a SIP from New Mexico to address the interstate transport provisions of CAA 110(a)(2)(D)(i) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS. In this submission, the state indicated that it intended to meet the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility by submission of a timely RH SIP. To date, the state has not made a RH SIP submission. In addition, the state has not made a submission demonstrating noninterference with the visibility programs of other states in accordance with section 110(a)(2)(D)(i)(II) by any other means.

In prior actions, we approved the New Mexico SIP submittal for (1) the "significant contribution to nonattainment" prong of section 110(a)(2)(D)(i) (75 FR 33174, June 11, 2010) and (2) the "interfere with maintenance" and "interfere with measures to prevent significant deterioration" prongs of section 110(a)(2)(D)(i) (75 FR 72688, November 26, 2010). In this action, we are proposing to disapprove the New Mexico Interstate Transport SIP with respect to the requirement that emissions from New Mexico sources do not interfere with measures required in the SIP of any other state to protect visibility. *See* CAA section 110(a)(2)(D)(i)(II). We are proposing to promulgate a FIP in order to cure this defect in the New Mexico Interstate Transport SIP.

2. Visibility Protection

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas [3] which impairment results from manmade air pollution." CAA § 169A(a)(1). The terms "impairment of visibility" and "visibility impairment" are defined in the Act to include a reduction in visual range and atmospheric discoloration. *Id.* section 169A(g)(6). In 1980, we promulgated regulations to address visibility impairment in Class I areas that is "reasonably attributable" to a single source or small group of sources, *i.e.*, "reasonably attributable visibility impairment" (RAVI). 45 FR 80084 (December 2, 1980). These regulations represented the first phase in addressing visibility impairment. We deferred action on RH that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved. *Id.*

Congress added section 169B to the CAA in 1990 to address RH issues, and we promulgated regulations addressing RH in 1999. 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (the regional haze rule or RHR). The RHR revised the existing visibility regulations to integrate provisions addressing RH impairment and established a comprehensive visibility protection program for Class I areas. The requirements for RH, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. States were required to submit the first SIP addressing RH visibility impairment no later than December 17, 2007. 40 CFR 51.308(b).

On January 15, 2009, we published a "Finding of Failure to Submit State Implementation Plans Required by the 1999 regional haze rule." 74 FR 2392. We found that New Mexico and other states had failed to submit for our review and approval complete SIPs for improving visibility in the nation's national parks and wilderness areas by the required date of December 17, 2007. We found that New Mexico failed to submit the plan elements required by 40 CFR 51.309(g), the reasonable progress requirements for areas other than the 16 Class I areas covered by the Grand Canyon Visibility Transport Commission Report. New Mexico also failed to submit the plan element required by 40 CFR 51.309(d)(4), which

[3] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. CAA section 162(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. *See* 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. CAA section 162(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager" (FLM). CAA section 302(i). When we use the term "Class I area" in this action, we mean a "mandatory Class I Federal area."

requires BART for stationary source emissions of NO_x and PM under either 40 CFR 51.308(e)(1) or 51.308(e)(2).[4] This finding started a 2-year clock for the promulgation of a FIP by EPA, unless the State made a RH SIP submission and we approved it.

3. Best Available Retrofit Technology

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain major stationary sources with the potential to emit greater than 250 tons or more of any pollutant, in order to address visibility impacts from these sources. Specifically, it requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources built between 1962 and 1977 procure, install, and operate the "Best Available Retrofit Technology," as determined by the State or us in the case of a plan promulgated under section 110(c) of the CAA. CAA section 169A(b)(2)(A). States are directed to conduct BART determinations for such sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The RHR required all states to submit implementation plans that, among other measures, contain either emission limits representing BART for certain sources constructed between 1962 and 1977, or alternative measures that provide for greater reasonable progress than BART. 40 CFR 51.308(e). On July 6, 2005, we published the *Guidelines for BART Determinations Under the Regional Haze Rule* ("BART Guidelines") to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. 70 FR 39104.

The process of establishing BART emission limitations can be logically broken down into three steps: first, states identify those sources which meet the definition of "BART-eligible source" set forth in 40 CFR 51.301[5]; second, states determine whether each source "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area" (a source which fits this description is "subject to BART"); and third, for each source subject to BART, states then identify the appropriate type and the level of control for reducing emissions.

States must consider the following factors in making BART determinations: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. 40 CFR 51.308(e)(1)(ii)(A). Section 51.308(e)(1)(ii)(B) requires that BART determinations for fossil fuel-fired electric generating plants with a total generating capacity in excess of 750 megawatts, must be made according to the BART Guidelines.[6] A state is encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources.

States must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO_2, NO_X, and PM. We have stated that states should use their best judgment in determining whether volatile organic compounds (VOCs) or ammonia (NH_3) and ammonia compounds impair visibility in Class I areas.

The Regional Planning Organizations (RPOs) provided air quality modeling to the states to help them in determining whether potential BART sources can be reasonably expected to cause or contribute to visibility impairment in a Class I area. Under the BART Guidelines, states may select an exemption threshold value for their BART modeling, below which a BART-eligible source would not be expected to cause or contribute to visibility impairment in any Class I area. 70 FR 39104. The state must document this exemption threshold value in the SIP and must state the basis for its selection of that value. *Id.* Any source with emissions that model above the threshold value would be subject to a BART determination review. *Id.* The BART Guidelines acknowledge varying circumstances affecting different Class I areas. States should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. *Id.* Any exemption threshold set by the state should not be higher than 0.5 deciview. *Id.*

The RHR establishes the deciview (dv) as the principal metric for measuring visibility. *Id.* This visibility metric expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility is sometimes expressed in terms of the visual range which is the greatest distance, in kilometers or miles, at which a dark object can just be distinguished against the sky. The deciview is a more useful measure for tracking progress in improving visibility, because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview.

A RH SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five (5) years after the date of our approval of the RH SIP. CAA section 169(g)(4); 40 CFR 51.308(e)(1)(iv). In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source. *See* CAA section 110(a)(2).

4. The Western Regional Air Partnership and Evaluation of Regional Haze Impacts

The Western Regional Air Partnership (WRAP) is a voluntary partnership of state, tribal, federal, and local air agencies dealing with regional air quality issues in the West. Member states include Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. The WRAP established various committees to assist in managing and developing RH work products. New Mexico is a WRAP member. The WRAP evaluates air quality impacts, including RH impacts, associated with regionally significant emission sources. In so doing, the WRAP has conducted air quality modeling. The states in the West have

[4] NM has an option to submit a RH SIP under either section 51.308 or section 51.309. Although they have indicated their preference is for the latter, the NO_x BART FIP we are proposing would apply to either.

[5] BART-eligible sources are those sources, which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, that were put in place between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories.

[6] Appendix Y to 40 CFR Part 51—Guidelines for BART Determinations Under the Regional Haze Rule.

used this modeling to establish their reasonable progress goals for RH.[7]

The RH program, as reflected in the regulations, recognizes the importance of addressing the long-range transport of pollutants for visibility and encourage states to work together to develop plans to address haze. The regulations explicitly require each State to address its "share" of the emission reductions needed to meet the reasonable progress goals for surrounding Class I areas. States working together through a regional planning process are required to address an agreed upon share of their contribution to visibility impairment in the Class I areas of their neighbors. 40 CFR 51.308(d)(3)(ii). The States in the West worked together through the WRAP to determine their contribution to visibility impairment at the relevant federal Class I areas in the region and the emissions reductions from each State needed to attain the reasonable progress goals for each area. Regional planning organizations (RPOs) such as the WRAP provided much of the technical work necessary to develop RH SIPs, including the modeling used to establish reasonable progress goals. The WRAP evaluated air quality impacts, including RH impacts, associated with regionally significant emission sources. In so doing, the WRAP conducted air quality modeling. The modeling done by the RPOs relied on assumptions regarding emissions over the relevant planning period. Embedded in these assumptions were anticipated emissions reductions from each of the states in the RPO, including reductions from BART and other measures to be adopted as part of the states long-term strategy for addressing RH. The states in the West, in turn, have used this modeling to establish their reasonable progress goals for RH. The reasonable progress goals in the draft and final RH SIPs that have now been prepared by states in the West accordingly are based, in part, on the emissions reductions from nearby states that were agreed on through the WRAP process.

III. Our Evaluation

A. New Mexico's Interstate Transport SIP

We received a SIP from New Mexico to address the interstate transport provisions of CAA 110(a)(2)(D)(i) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS on September 17, 2007. Concerning the provision preventing sources in the state from emitting pollutants in amounts which will interfere with efforts to protect visibility in other states, New Mexico stated that:

- New Mexico sources of emissions do not interfere with implementation of reasonably attributable visibility impairment;
- Its December 2003 RH SIP demonstrated reasonable progress in reducing impacts on Class I areas on the Colorado Plateau;[8] and
- The 2007 SIP update for RH will analyze any impacts from New Mexico that extend beyond the Colorado Plateau and determine appropriate long-term strategies for control measures. As mentioned previously, New Mexico has yet to provide this SIP revision.

New Mexico's submission addressed the requirement that it not interfere with the visibility programs of other states by stating that it would submit an approvable RH SIP by December 2007. The state did not otherwise establish that emissions from its sources would not interfere with the visibility programs of other states. After intervening events precluded the development of an approvable RH SIP, the state did not make any subsequent SIP submission to address the requirements of section 110(a)(2)(D)(i)(II) with respect to impacts on the visibility programs of other states. Consequently, because the State did not submit a RH SIP or an alternative means of demonstrating that emissions from its sources would not interfere with the visibility programs of other States, we are proposing disapproval of the SIP received September 17, 2007, with respect to 110(a)(2)(D)(i)(II) and visibility protection. Further, as described in subsequent sections, we are proposing that additional controls are necessary to prevent emissions from New Mexico from interfering with measures to protect visibility in other States.

B. Federal Implementation Plan To Address Interstate Transport and Visibility and the BART Requirements for NO_X

As an initial matter, we note that section 110(a)(2)(D)(i)(II) does not explicitly specify how we should ascertain whether a state's SIP contains adequate provisions to prevent emissions from sources in that state from interfering with measures required in another state to protect visibility. Thus, the statute is ambiguous on its face, and we must interpret that provision.

Our 2006 Guidance recommended that a state could meet the visibility prong of the transport requirements of section 110(a)(2)(D)(i)(II) of the CAA by submission of the RH SIP, due in December 2007. Our reasoning was that the development of the RH SIPs was intended to occur in a collaborative environment among the states. In fact, in developing their respective reasonable progress goals, WRAP states consulted with each other through the WRAP's work groups.[9] As a result of this process, the common understanding was that each State would take action to achieve the emissions reductions relied upon by other states in their reasonable progress demonstrations under the RHR. This effort included all states in the WRAP region contributing information to a Technical Support System (TSS) which provides an analysis of the causes of haze, and the levels of contribution from all sources within each state to the visibility degradation of each Class I area. The WRAP states consulted in the development of reasonable progress goals, using the products of this technical consultation process to co-develop their reasonable progress goals for the Western Class I areas.

We believe that the analysis conducted by the WRAP provides an appropriate means for designing a FIP that will ensure that emissions from sources in New Mexico are not interfering with the visibility programs of other states, as contemplated in section 110(a)(2)(D)(i)(II). In developing their visibility projections using photochemical grid modeling, the WRAP states assumed a certain level of emissions from sources within New Mexico. Although we have not yet received all RH SIPs, we understand that the WRAP states used the visibility projection modeling to establish their own respective reasonable progress goals. Thus, we believe that an implementation plan that provides for emissions reductions consistent with the assumptions used in the WRAP modeling will ensure that emissions from New Mexico sources do not

[7] More information on WRAP and their work can be found on the Internet at *http://www.wrapair2.org* and in the TSD for this action.

[8] In December, 2003, New Mexico submitted its RH SIP pursuant to the requirements of sections 169A and 169B of the CAA and the regional haze rule. However, in *American Corn Growers Ass'n* v. *EPA*, 291 F.3d 1 (DC Cir. 2002), the U.S. Court of Appeals for the District of Columbia Circuit issued a ruling vacating and remanding the BART provisions of the regional haze rule. In 2006, EPA issued BART guidelines to address the court's ruling in that case. *See* 70 FR 39104 (July 6, 2005). On January 13, 2009, New Mexico resubmitted portions of its RH SIP, but not the requirements addressing reasonable progress pursuant to 40 CFR 51.309(g).

[9] Consultation provided through the WRAP have been documented in calls and meetings on the WRAP Web site, *available* at *http://www.wrapair.org/cal/calendar.php*.

interfere with the measures designed to protect visibility in other states.

Accordingly, we have reviewed the WRAP photochemical modeling emission projections used in the demonstration of reasonable progress towards natural visibility conditions and compared them to current emission levels from sources in New Mexico. We have concluded that all of the sources in New Mexico are achieving the emission levels assumed by the WRAP in its modeling except for the SJGS. The WRAP modeling assumed the SJGS's NO_X emissions would be 0.27 lbs/MMBtu for units 1 and 3, and 0.28 lbs/MMBtu for units 2 and 4, in 2018. The WRAP modeling also assumed SO_2 emissions would be 0.15 lbs/MMBtu in 2018 for the four SJGS units.

The SJGS consists of four (4) coal-fired generating units and associated support facilities. Each coal-fired unit burns pulverized coal and No. 2 diesel oil (for startup) in a boiler, and produces high-pressure steam which powers a steam turbine coupled with an electric generator. Electric power produced by the units is supplied to the electric power grid for sale. Coal for the units is supplied by the adjacent San Juan Mine and is delivered to the facility by conveyor. Units 1 and 2 have a unit capacity of 350 and 360 MW, respectively. Units 3 and 4 each have a unit capacity of 544 MW.

In 2005, the operator of the SJGS, Public Service Company of New Mexico (PNM), entered into a consent decree with the Grand Canyon Trust, Sierra Club, and the New Mexico Environment Department (NMED) to reduce emissions of NO_X, SO_2, particulate matter and mercury.[10] The consent decree imposed emissions restrictions, including the following:

- NO_X: 0.30 lb/mmBtu on a 30-day rolling average.
- SO_2: 90% annual average control, not to exceed 0.250 lb/mmBtu for a seven-day block average.

In a permit modification to the construction permit for SJGS, NMED issued a revised construction permit (NSR Air Quality Permit No. 0063–M6) on April 22, 2008 to incorporate some of the conditions from the consent decree. The construction permit was issued by the Air Quality Bureau of the NMED to SJGS pursuant to the New Mexico Air Quality Control Act and regulations and is considered a federally enforceable permit. We were not a party to the consent decree, but the inclusion of limits from the consent decree that have been included in the construction permit for the facility were issued pursuant to the federally approved construction permitting program of the New Mexico SIP. Specifically, the construction permit includes the NO_X and SO_2 limits from the consent decree that are identified above.[11] Therefore, these NO_X and SO_2 emissions restrictions are federally enforceable. This permit has since been superseded by a further construction permit modification that also includes the consent decree limits on NO_X and SO_2 emissions and is federally enforceable.[12]

Although the SJGS is subject to a federally enforceable permit, the permit's 30-day rolling average NO_X emission limit of 0.30 lb/mmBtu for all units is less restrictive than the emission rates modeled by the WRAP of 0.27 lbs/MMBtu for units 1 and 3, and 0.28 lbs/MMBtu for units 2 and 4 in assessing the daily visibility impacts. We also note the WRAP photochemical modeling utilized an SO_2 emission rate of 0.15 lbs/MMBtu on a continuous basis for all four units. In previous communications to New Mexico and the WRAP, PNM indicated that the 90% annual average control specified in the permit would be expected to yield roughly an annual average emission rate of 0.195 lb/mmBtu of SO_2,[13] which is much higher than the 0.15 lb/mmBtu emission rate utilized in the WRAP's photochemical modeling for assessing daily level impacts. Also, the 90% SO_2 control restriction specified in the permit is an annual average, which allows for short term fluctuations. It also is not directly translatable to an emission limit (e.g., lbs/MMBtu), and requires knowledge of the sulfur content of the coal being burned. Therefore, this limit can further fluctuate depending upon the annual average sulfur content of the coal. This presents an unnecessary enforcement complication. The permit also specifies a 0.250 lb/mmBtu on a 7-day block average for each unit, which is much less restrictive than the 0.15 lb/mmBtu emission rate that was used within the WRAP's photochemical modeling.

Therefore, the permit does not provide the necessary emission limits and enforceable mechanisms to ensure the NO_X and SO_2 emissions used in the WRAP photochemical modeling for the SJGS units will be met. In the absence of an approvable RH SIP, we do not have an enforceable mechanism for ensuring that sources in New Mexico do not impact visibility in other states. Other WRAP states are relying on levels modeled for the SJGS units, developed in consultation, in their demonstration of reasonable progress towards natural visibility conditions. Therefore, any discrepancies between what was included in the WRAP photochemical modeling and what is presently enforceable, is a concern. We have evaluated these discrepancies and determined they are significant due to the changes in visibility projections in the modeling. We have concluded that it is appropriate to establish federally enforceable limits for pollutants that impact visibility projections within the WRAP photochemical modeling.

As discussed in II.A, we are proposing to disapprove New Mexico Interstate Transport SIP provisions that address the requirement of section 110(a)(2)(D)(i)(II) that emissions from New Mexico sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. In addition, since New Mexico has not submitted a complete RH SIP that should have, among other things, included a review of BART for NO_X at the SJGS, and for both of these requirements we have made a finding of failure to submit,[14] giving us the authority and responsibility to issue a FIP to address the deficiencies in the State's plan, we are also proposing to find that New Mexico sources, except the SJGS, are sufficiently controlled to eliminate interference with the visibility programs of other states. For the SJGS we are proposing to impose specific emissions limits that will eliminate such interstate interference based on current emissions that satisfies the assumptions in the WRAP modeling.

The following sections outline our proposal for addressing the BART requirements for NO_X at SJGS and for ensuring that the SJGS has the controls necessary to prevent emissions from

[10] Consent Decree in *The Grand Canyon Trust and Sierra Club, Plaintiffs, The State of New Mexico, Plaintiff-Intervenor,* v. *Public Service Company of New Mexico, Defendant,* (CV 02–552 BB/ACT (ACE)), lodged in the United States District Court, District of New Mexico, on March 10, 2005, at 15–16.

[11] NO_X limit of 0.30 lb/mmBtu on a 30-day rolling average for each of the four units; SO_2 limit of 90% annual average control for each unit, with a short-term limit not to exceed 0.250 lb/mmBtu for a seven-day block average.

[12] New Mexico Environment Department Air Quality Bureau NSR Air Quality Permit No. 0063–M6R1 was issued on September 12, 2008 and superseded Permit No. 0063–M6.

[13] Comments Received to-Date on the Draft 2018 Base Case Projections, Version: December 21, 2005, *available* at *http://www.wrapair.org/forums/ssjf/documents/eictts/Projections/Summary%20of%20Comments_122105_final.pdf,* pdf pagination 20.

[14] *See* Finding of Failure to Submit SIPs for Interstate Transport for the 8-hour Ozone and $PM_{2.5}$ NAAQS. 70 FR 21147 (April 25, 2005); *see also* Finding of Failure To Submit State Implementation Plans Required by the 1999 Regional Haze Rule. 74 FR 2392 (January 15, 2009).

New Mexico from interfering with the reasonable progress goals in other states.

1. Additional SO_2 Emission Limits for the SJGS

As we discuss above, there are no federally enforceable limits that restrict the SJGS's SO_2 emissions at 0.15 lbs/MMBtu, the rate assumed by the WRAP in its modeling. Therefore, as part of this action, we are proposing to impose an SO_2 emission rate of 0.15 lbs/MMBtu on a 30 day rolling average for units 1, 2, 3, and 4 of the SJGS. By imposing this limit through this action, we will insure that SO_2 emissions from this source are not interfering with the visibility programs of other states. We note an examination of the SJGS's actual emission rates based on emissions reported by our Clean Air Markets Division [15] indicates units 1, 2, 3, and 4 of the SJGS are already meeting these SO_2 emission limits.

We are not making a finding that this SO_2 emission limit satisfies BART for SO_2. NMED has indicated they will submit a RH SIP under 40 CFR 51.309, thus SO_2 BART for the SJGS will be addressed through New Mexico's participation in an SO_2 trading program, under 40 CFR 51.309(d)(4). Should NMED instead submit a RH SIP under 40 CFR 51.308, the SJGS would be subject to an SO_2 BART analysis under 40 CFR 51.308(e).

2. Need for Additional NO_X Controls

As we discuss above, the WRAP assumed in its modeling that the SJGS would achieve NO_X emission rates of 0.27 lbs/MMBtu for units 1 and 3, and 0.28 lbs/MMBtu for units 2 and 4 in its evaluation of daily impacts in photochemical modeling. Based on our approach of relying on the assumptions in the WRAP modeling, additional control would, therefore, be necessary to ensure that emissions from New Mexico sources do not interfere with efforts to protect visibility in other states pursuant to the requirements of section 110(a)(2)(D)(i)(II) of the CAA.

Unlike the case for SO_2, the SJGS will have to install controls and therefore make capital investments to achieve these additional NO_X reductions. As we note above, on January 15, 2009, we published a "Finding of Failure to Submit State Implementation Plans Required by the 1999 regional haze rule." 74 FR 2392. This finding included the plan element required by 40 CFR 51.309(d)(4), which requires BART for stationary source emissions of NO_X and PM under either 40 CFR 51.308(e)(1) or 51.308(e)(2). Therefore, rather than making an initial determination to require the controls needed to prevent interference with the visibility programs of other states based on the assumptions in the WRAP photochemical modeling to meet section 110(a)(2)(D)(i)(II) requirements, followed soon thereafter by a separate NO_X BART evaluation, we find it is appropriate to perform that BART evaluation at this time. Addressing both outstanding obligations at this time will be more efficient and will provide greater certainty to the source as to the appropriate NO_X controls needed to meet these two separate but related requirements. Our evaluation of BART for NO_X follows.

3. NO_X BART Evaluation

In June, 2007, PNM submitted its BART evaluation to NMED. That evaluation was revised multiple times to incorporate additional visibility modeling analyses, control technology considerations, and cost analyses. Although not officially submitted to us, NMED completed a NO_X and PM BART determination for the SJGS (referred to herein as the "NMED BART evaluation"), which we have found to be thorough and comprehensive.[16] In making our NO_X BART determination for the SJGS, we drew heavily upon the NO_X BART portion of that document, and used it to help inform our NO_X BART determination for the SJGS. We have incorporated it into our Technical Support Document (TSD) found in the electronic docket for this action. The electronic docket can be found at the Web site *http://www.regulations.gov* (docket number EPA–R06–OAR–2010–0846).

We have determined, as outlined below, that the SJGS is subject to BART and are proposing to require that units 1, 2, 3, and 4 meet an emission limit for NO_X of 0.05 lbs/MMBtu. This limit is based on the installation of SCR on each of the units. The following steps outline how we came to this determination. For more detail, please see the TSD. Any BART determinations for other pollutants that may be warranted under the RHR will be addressed in future rulemakings.

a. The SJGS Is a BART-Eligible Source

The first step of a BART evaluation is to determine whether a source meets the definition of a "BART-eligible source" in 40 CFR 51.301. BART-eligible sources are those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. We find, based on emissions reported by our Clean Air Markets Division,[17] that units 1, 2, 3, and 4 of the SJGS each have historically emitted much more than 250 tons of NO_X. Also, according to the NMED SJGS Title V Statement of Basis, units 1, 2, 3, and 4 of the SJGS meet the requirement of being "in existence" on August 7, 1977 but not "in operation" before August 7, 1962. Lastly, we find that units 1, 2, 3, and 4 of the SJGS fall under category 1 of the 26 listed BART categories, which is fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input. Therefore, we propose to find that units 1, 2, 3, and 4 of the SJGS are BART-eligible.

b. The SJGS Is Subject to BART

Section III of the BART Guidelines outlines several approaches for identifying sources that are subject to BART. This entails making a determination of whether the units of the SJGS cause or contribute to visibility impairment in nearby Class I areas. Among the options we recommended was the use of dispersion modeling for assessing the impacts of a single source. As we note in the BART Guidelines, one of the first steps in this approach to determining whether a source causes or contributes to visibility impairment is to establish a threshold (measured in deciviews). A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still contribute to visibility impairment and thus be subject to BART. We note in the BART Guidelines that states (and by extension EPA when promulgating a FIP) have flexibility in determining an appropriate threshold for determining whether a source "contributes to any visibility impairment" for the purposes of BART. However, this threshold should not be higher than 0.5 deciviews.[18] In the case of the SJGS, this establishment of a precise threshold for contribution is moot, since visibility modeling indicates that even using the upper bound contribution threshold of 0.5 deciviews, the SJGS contributes to

[15] *http://camddataandmaps.epa.gov/gdm/index.cfm.*

[16] New Mexico Environment Department, Air Quality Bureau, BART Determination, Public Service Company of New Mexico, San Juan Generating Station, Units 1–4, June 21, 2010, *available* at *http://www.nmenv.state.nm.us/aqb/reghaz/documents/AppxA_NM_SJGS_NOxBART Determination_06212010.pdf.*

[17] *http://camddataandmaps.epa.gov/gdm/index.cfm.*

[18] 40 FR 39161 (July 6, 2005).

visibility impairment at a number of Class I areas.

The WRAP performed the initial BART screening modeling for the state of New Mexico. The procedures used are outlined in the WRAP Regional Modeling Center (RMC) BART Modeling Protocol.[19] The WRAP screening modeling evaluated sources that were identified as BART-eligible and determined the only sources that did not screen out were the SJGS units. The results of this analysis indicated that SJGS, on a facility-wide basis, causes visibility impairment at all 16 Class I areas within 300 km of the facility. However, this modeling was based on the installed control technology at the time and does not reflect emission reductions due to the installation of consent decree controls. Revised modeling performed by NMED and by us, including controls required by the consent decree and currently installed, further confirmed that SJGS still "causes" visibility impairment at more than half of the Class I areas in the vicinity of the facility and contributes (above 0.5 deciviews) to visibility impairment at the remaining areas on a facility-wide basis. On an individual unit basis, all units "cause" visibility impairment at Mesa Verde National Park, and cause or contribute to visibility impairment at a number of other Class I areas. Our modeling indicates that the visibility impairment is primarily dominated by nitrate particulates. Therefore, as the WRAP screening modeling has previously concluded and further New Mexico and our modeling confirms that even with post-consent decree control levels on SJGS units, the SJGS units 1, 2, 3, and 4 still have a significant impact at surrounding Class I areas. Consequently, we propose to find that units 1, 2, 3, and 4 of the SJGS are subject to BART. More details on this determination can be found in the TSD.

c. The SJGS NO_X BART Determination

Having established that units 1, 2, 3, and 4 of the SJGS are subject to BART, the next requirement is to perform the BART Analysis. 40 CFR 51.308(e)(1)(ii); *see also* BART Guidelines, Section IV.

The BART analysis identifies the best system of continuous emission reduction and, as laid out in the BART Guidelines, consists of the following five basic steps:

- Step 1: Identify All Available Retrofit Control Technologies;
- Step 2: Eliminate Technically Infeasible Options;
- Step 3: Evaluate Control Effectiveness of Remaining Control Technologies;
- Step 4: Evaluate Impacts and Document the Results; and
- Step 5: Evaluate Visibility Impacts.

As we stated above, for our BART analysis we have heavily drawn upon the NMED BART Evaluation. Except for the following points, we agree with NMED's conclusions regarding Steps 1–5:

- PNM's cost estimate. NMED questioned PNM's cost estimate for the installation of SCR but accepted it as being cost effective. We too questioned PNM's cost estimate for SCR, and hired a consultant to undertake an accurate assessment of the cost of SCR and the emission limits that SCR is capable of attaining. (For more information, please see the TSD).
- BART for NO_X. NMED evaluated the visibility benefits of SCR at the SJGS based on an emission limit of 0.07 lbs/MMBtu, but noted the potential for greater control at rates as low as 0.03 lbs/MMBtu. As discussed further below, we have concluded that a NO_X emission limit of 0.05 lbs/MMBtu is BART for the SJGS, and performed our visibility modeling on that basis. (Additional information is provided in the TSD).
- SO_2 to SO_3 Conversion. NMED concluded BART for the SJGS was SCR plus sorbent injection to remove sulfur trioxide (SO_3) in the flue gas by reaction with an alkaline material. As discussed further below, we have concluded that sorbent injection is not necessary, as the SJGS burns a low sulfur coal, and catalysts are available with a low SO_2 to SO_3 conversion rate. (Please see the TSD for further information).

The following is a summary of our BART analysis. In general, our analysis is the same as NMED's analysis of Steps 1–5, as modified to incorporate the areas discussed above in which we differ with NMED.

i. Identification of All Available Retrofit Emission Control Technologies

To address step 1, NMED reviewed a number of potential retrofittable NO_X control technologies, including: Selective Non Catalytic Reduction (SNCR), SCR, SNCR/SCR Hybrid, Natural Gas Reburn, Nalco Mobotec ROFA and Rotamix, NOxStar, ECOTUBE, PowerSpan ECO, Phenix Clean Combustion, and e-SCRUB. We drew upon PNM's June, 2007 BART submission to NMED and its subsequent revisions in our evaluation, and agree that the potential technologies for NO_X controls that have been identified.

ii. Elimination of Technically Infeasible Options

For step 2, again drawing upon the NMED analysis, we have determined the following potentially retrofittable NO_X control technologies are not technically feasible, or have not been thoroughly demonstrated on similar size and type units: Natural Gas Reburn, NOxStar, ECOTUBE, PowerSpan ECO, Phenix Clean Combustion, and e-SCRUB. In determining BART, we have considered the remaining technologies, SCR, SNCR, SNCR/SCR Hybrid, and the Nalco Mobotec ROFA and Rotamix to be technically feasible.

iii. Evaluation of Control Effectiveness of Remaining Control Technologies

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2. Two key issues in this process include: (1) Ensuring the degree of control is expressed using a metric that ensures a level comparison of emissions performance levels among options; and (2) giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels. With the exception of SCR, Table 1 represents the control efficiencies and control emission rates PNM reported as part of its BART analyses[20] to NMED for the NO_X controls that were found to be technically feasible. In our own SCR cost analysis, which we present later in this section, we have revised the control efficiency for SCR from 0.07 lbs/MMBtu to 0.05 lbs/MMBtu.

[19] "CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States", Western Regional Air Partnership (WRAP); Gail Tonnesen, Zion Wang; Ralph Morris, Abby Hoats and Yiqin Jia, August 15, 2006, *available* at *http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf*.

[20] Public Service Company of New Mexico, San Juan Generating Station, Best Available Retrofit Technology Analysis, June 6, 2007.

PNM San Juan Generating Station, BART Analysis of SNCR, May 30, 2008.

PNM San Juan Generating Station, BART Analysis of Nalco Mobotec NO_X Control Technologies, August 29, 2008.

TABLE 1—PROJECTED NO_X CONTROL EFFECTIVENESS FOR UNITS 1–4

Control technology	Control efficiency (%)	Controlled emission rate (lb/MMbtu)
ROFA	13–15	0.26
Rotamix (SNCR)	23–25	0.23
ROFA/Rotamix	33–35	0.20
SCR/SNCR Hybrid	40–41	0.18
SCR	77	0.07

iv. Evaluation of Impacts and Documentation of Results

Under step 4 of the BART determination process, we conducted the following analysis of the possible impacts due to the installation of the technically feasible NO_X control options:

- Costs of Compliance.
- Energy Impacts.
- Non-Air Quality Environmental Impacts.
- Remaining Useful Life.

When performing BART analyses on each of the technically feasible NO_X control options, PNM considered the energy impacts, non-air quality environmental impacts, and the remaining useful life. PNM accounted for the additional cost of certain energy impacts in the cost impacts analysis. It did not note any other energy impacts as being significant. With regard to non-air quality environmental impacts, PNM did not identify any significant or unusual environmental impacts associated with the control alternatives that had the potential to affect the selection or elimination of that control alternative. For SCR and SCR/SNCR Hybrid technologies, the non-air quality environmental impacts included the consideration of water usage and waste generated from each control technology. Lastly, the remaining useful life was defined by PNM as 20 years. Therefore, no additional cost adjustments for a short remaining useful boiler life were claimed by PNM.

PNM calculated the costs of each of the technically feasible NO_X control options [21]. This information was assessed by NMED in its BART analysis. We checked that information and present it below in Tables 2–5 (with a few minor corrections). It summarizes our evaluation of the impacts of the BART analyses, including updated cost data for the SCR option:

TABLE 2—IMPACT ANALYSIS AND COST EFFECTIVENESS OF NO_X CONTROL TECHNOLOGIES FOR UNIT 1

Control technology	Emission limit (lbs/MMBtu)	NO_X emissions (tpy)	NO_X reduction (tpy)	Total capital investment (TCI) (1,000$)	Total annualized cost (TAC) (1,000$)	Cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Energy impacts (1,000$)	Non-air impacts (1,000$)
SCR + sorbent	0.07	966	3,174	164,732	21,998	6,931	3,815	1,569	[1] NA
SNCR/SCR Hybrid	0.18	2,484	1,656	104,436	16,207	9,787	34,221	706	1,762
ROFA/Rotamix	0.20	2,760	1,380	29	6,762	4,900	7,766	1,413	3
Rotamix (SNCR)	0.23	3,174	966	11,306	3,547	3,672	222	51	4
ROFA	0.26	3,588	552	18,293	3,455	6,259	−2,896	1,363	[1] NA
Consent Decree	0.30	4,140	1,254	14,580	1,422	1,134	NA	[1] NA	[1] NA

TABLE 3—IMPACT ANALYSIS AND COST EFFECTIVENESS OF NO_X CONTROL TECHNOLOGIES FOR UNIT 2

Control technology	Emission limit (lbs/MMBtu)	NO_X emissions (tpy)	NO_X reduction (tpy)	Total capital investment (TCI) (1,000$)	Total annualized cost (TAC) (1,000$)	Cost effectivness ($/ton)	Incremental cost effectiveness ($/ton)	Energy impacts (1,000$)	Non-air impacts (1,000$)
SCR + sorbent	0.07	961	3,158	177,178	23,364	7,399	4,432	1,565	[1] NA
SNCR/SCR Hybrid	0.18	2,471	1,648	108,628	16,670	10,118	36,082	346	1,762
ROFA/Rotamix	0.20	2,746	1,373	29,350	6,762	4,925	7,805	1,413	3
Rotamix (SNCR)	0.23	3,158	961	11,306	3,547	3,691	223	51	4
ROFA	0.26	3,570	549	18,293	3,455	6,291	−1,375	1,363	[1] NA
Consent Decree	0.30	4,119	2,060	14,126	1,378	669	NA	[1] NA	[1] NA

TABLE 4—IMPACT ANALYSIS AND COST EFFECTIVENESS OF NO_X CONTROL TECHNOLOGIES FOR UNIT 3

Control technology	Emission limit (lbs/MMBtu)	NO_X emissions (tpy)	NO_3 reduction (tpy)	Total capital investment (TCI) (1,000$)	Total annualized cost (TAC) (1,000$)	Cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Energy impacts (1,000$)	Non-air impacts (1,000$)
SCR + sorbent	0.07	1,501	4,930	227,774	30,527	6,192	2,087	2,267	[1] NA

[21] Tables 2–5 were constructed to incorporate costs due to sorbent injection, as a means of SO_3 control in conjunction with SCR. This was done by PNM in response to a request by NMED. As NMED notes in its BART analysis, it understands there are SCR catalysts now on the market that are capable of a much smaller SO_2 to SO_3 conversion. In our own analysis, we have concurred with this finding and hence do not consider sorbent injection.

TABLE 4—IMPACT ANALYSIS AND COST EFFECTIVENESS OF NO_X CONTROL TECHNOLOGIES FOR UNIT 3—Continued

Control technology	Emission limit (lbs/MMBtu)	NO_X emissions (tpy)	NO_3 reduction (tpy)	Total capital investment (TCI) (1,000$)	Total annualized cost (TAC) (1,000$)	Cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Energy impacts (1,000$)	Non-air impacts (1,000$)
SNCR/SCR Hybrid	0.18	3,859	2,572	168,507	25,606	9,954	37,221	507	2,658
ROFA/Rotamix	0.20	4,287	2,144	34,070	9,648	4,501	7,338	2,810	5
Rotamix (SNCR)	0.23	4,930	1,501	13,316	4,929	3,285	−303	84	5
ROFA	0.26	5,574	857	20,983	5,124	5,976	−2,264	2,725	[1] NA
Consent Decree	0.30	6,431	2,573	12,715	1,240	482	NA	[1] NA	[1] NA

TABLE 5—IMPACT ANALYSIS AND COST EFFECTIVENESS OF NO_X CONTROL TECHNOLOGIES FOR UNIT 4

Control technology	Emission limit (lbs/MMBtu)	NO_X emissions (tpy)	NO_X reduction (tpy)	Total capital investment (TCI) (1,000$)	Total annualized cost (TAC) (1,000$)	Cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Energy impacts (1,000$)	Non-air impacts (1,000$)
SCR + sorbent	0.07	1,472	4,837	211,764	28,760	5,946	1,691	2,288	[1] NA
SNCR/SCR Hybrid	0.18	3,785	2,524	161,572	24,849	9,847	36,141	507	2,658
ROFA/Rotamix	0.20	4,206	2,103	34,070	9,648	4,588	7,480	2,810	5
Rotamix (SNCR)	0.23	4,837	1,472	13,316	4,929	3,348	−309	84	5
ROFA	0.26	5,468	841	20,983	5,124	6,091	−2,299	2,275	[1] NA
Consent Decree	0.30	6,309	2,524	12,870	1,256	498	NA	[1] NA	[1] NA

[1] PNM performed an impact analysis for these technologies and incorporated any monetized energy or non-air environmental impacts into the cost analysis

We find that the energy impacts, non-air quality environmental impacts, and the remaining useful life do not present sufficient reason to disqualify any of the technically feasible NO_X control technologies.

v. Evaluation of Visibility Impacts and Cost Analysis

Under step 5 of the BART Guidelines, we evaluate the visibility improvement for each feasible control technology. NMED modeled [22] the visibility benefits of each of the NO_X control technologies listed in Tables 2–5, above, on 16 Class I areas. NMED used the CALPUFF modeling system, which consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF modeling system is the recommended model for conducting BART visibility analysis. First, the model was run using the pre-BART, consent decree conditions to establish a baseline. The model was then run for each of the control technologies identified for each unit during the BART engineering analysis. These visibility impacts were then compared to the baseline to evaluate the visibility benefit of each control. NMED modeled the visibility impacts of each of the control scenarios individually for each of the SJGS units, as well as calculated visibility impacts on a facility-wide basis. The NMED modeling used the original IMPROVE equation within CALPOST to estimate visibility impairment from the modeled pollutant concentrations. Table 6, below, summarizes the results of the latter exercise, for the maximum impacts of the 98th percentile delta-dv impacts from 2001–2003.

All of the WRAP and NMED refined modeling was conducted with the version of the CALPUFF system recommended by the WRAP BART modeling protocol [23] and followed the WRAP protocol for source-specific applications. As we note in the TSD, NMED and the WRAP utilized CALMET version 6.211 to create the necessary meteorological database for input into the CALPUFF model. Some technical concerns have been identified with this non-regulatory version of the model. The concerns are discussed in the technical support document. Our regulatory version of the model is CALMET 5.8, which we used in our modeling. Two pollutants must be given special consideration when estimating the impact of various control technologies on visibility improvement: Background ammonia (NH_3) and sulfuric acid (H_2SO_4) emissions. NMED utilized a variable monthly background NH_3 concentration rather than using the default recommended value. As discussed later, we utilized both approaches for background NH_3 in our modeling so as to be able to compare the results. For estimating H_2SO_4 emissions, NMED estimated the fraction of particulate matter (PM) emissions that are classified as inorganic condensable PM and assumed that 100% of this fraction is H_2SO_4. Additional H_2SO_4 due to SCR operation was calculated assuming 1% conversion of SO_2 to SO_3. As noted in the TSD and briefly described below, our approach to these two factors differed from the NMED approach. The results provided by NMED, and included in Table 6 below, demonstrate that SCR is by far the most advantageous approach to NO_X control. The differences in our and New Mexico's approaches should not change the relative advantage that SCR has over other control methods in improving visibility since these concerns are present in all the NMED modeling and would have similar impacts on the modeling results.

[22] NMED performed some modeling as well as reviewed modeling protocols and results supplied by PNM and prepared by the contractor Black & Veatch found in: Public Service Company of New Mexico BART Technology Analysis for the San Juan Generating Station (June 6, 2007 and submittal updates). When we say "NMED modeling" or "NMED modeled" we are referring to the modeling performed or reviewed by NMED.

[23] "CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States", Western Regional Air Partnership (WRAP); Gail Tonnesen, Zion Wang; Ralph Morris, Abby Hoats and Yiqin Jia, August 15, 2006. *available* at *http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.*

TABLE 6—NMED MODELED MAXIMUM IMPACTS OF THE 98TH PERCENTILE DELTA-dv IMPACTS FROM 2001–2003

Class I area	Distance to SJGS (km)	Consent decree baseline	SCR + Sorbent	SCR/ SNCR Hybrid	ROFA/ Rotamix	Rotamix	ROFA
Arches	222	1.69	1.10	1.58	1.58	1.61	1.63
Bandelier Wilderness	210	1.56	0.80	1.33	1.28	1.35	1.41
Black Canyon of the Gunnison Wilderness	203	1.15	0.63	0.94	0.93	0.98	1.04
Canyonlands	170	2.26	1.59	2.17	2.10	2.13	2.17
Capitol Reef	232	1.81	1.08	1.64	1.55	1.62	1.68
Grand Canyon	285	0.97	0.53	0.80	0.79	0.84	0.88
Great Sand Dunes National Monument	269	0.71	0.40	0.64	0.60	0.61	0.65
La Garita Wilderness	169	0.94	0.45	0.78	0.74	0.79	0.83
Maroon Bells Snowmass Wilderness	271	0.56	0.28	0.48	0.47	0.50	0.52
Mesa Verde	40	3.80	2.46	4.42	3.58	3.58	3.59
Pecos Wilderness	248	1.09	0.66	0.90	0.88	0.92	0.97
Petrified Forest	213	0.82	0.48	0.73	0.73	0.77	0.78
San Pedro Parks Wilderness	155	2.01	1.13	1.80	1.67	1.77	1.86
West Elk Wilderness	216	0.91	0.43	0.73	0.71	0.76	0.80
Weminuche Wilderness	98	1.48	0.90	1.33	1.24	1.32	1.36
Wheeler Peak Wilderness	258	0.89	0.50	0.72	0.70	0.75	0.79
Total	....	22.65	13.42	20.99	19.55	20.30	20.96

We note NMED's modeling indicated there was little difference between the SCR/SNCR hybrid, ROFA/Rotamix, and ROFA NO_X control technologies. However, as Tables 2–5 indicate, there is a significant difference in the cost of those controls, with the SNCR/SCR hybrid being more than twice as expensive as the ROFA/Rotamix, and approximately five times as expensive as both the Rotamix (SNCR) and the ROFA options. None of these NO_X control technologies was capable of significantly improving the visibility at any of the 16 Class I areas; therefore, we did not further evaluate them. However, we note that SCR was capable of uniformly improving the visibility at all of the 16 Class I areas, but at a higher cost.

The costs of the controls in Tables 2–5, were calculated by PNM. Because we found the costs projected by PNM to be high in comparison to other SCR retrofits we have reviewed, we refined the cost of retrofitting the SJGS with SCR (see the TSD for more information), and the NO_X emission level SCR was capable of achieving when retrofitted to the SJGS. This analysis indicated that the cost of SCR at this source would be considerably lower than calculated by PNM. We believe that PNM overestimated the cost of SCR due to several basic errors that PNM made in constructing its SCR cost analysis:

• PNM did not follow the EPA Air Pollution Control Cost Manual, where possible,[24] as directed by the BART Guidelines.[25]

• PNM scaled many of the cost items from another project that has significant design differences when compared to the SJGS. We made changes in many of these items to adjust them from budgetary to final contract; to exclude equipment and modifications not required for the SJGS SCR installations; to correct errors; and to factor out installation, freight, and other costs that were included in the contract awards and double counted elsewhere in PNM's cost estimate. We have concluded that these adjustments are correct, and provide a more accurate estimate of the costs at SJGS.

• PNM performed their SCR cost estimate on the basis of a NO_X control rate of 0.07 lbs/MMBtu. We concluded that SCR could reliably achieve NO_X control at a rate of 0.05 lbs/MMBtu on a 30-day rolling average basis, for each of the four units of the SJGS. Because this did not require a change in the capital cost of the SCR unit, and only necessitated the purchase of additional reagent, this had the effect of improving the cost effectiveness. We have concluded that the analysis concerning the achievability of the emissions limit, and the cost of achieving those limits, is more accurate.

The results of that analysis are presented as Table 7:

TABLE 7—EPA DETERMINED COST EFFECTIVENESS OF SCR FOR THE SJGS

Unit	Emission limit (lbs/MMBtu)	NO_X emissions (tpy)	NO_X reduction (tpy)	Total capital investment	Total annualized cost	Cost effectiveness ($/ton)
1	0.05	690	3,450	$53,230,469	$6,373,573	1,847
2	0.05	686	3,433	55,664,049	6,591,720	1,920
3	0.05	1,071	5,360	70,464,306	8,631,234	1,610
4	0.05	1,051	5,258	67,223,223	8,304,143	1,579

[24] U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B–02–001, 6th Ed., January 2002 ("Cost Manual"), The EPA Air Pollution Control Cost Manual is the current name for what was previously known as the OAQPS Control Cost Manual, the name for the Cost Manual in previous (pre-2002) editions of the Cost Manual.

[25] In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. 70 FR 39104, 39166 (2005).

Based on our refined cost and control effectiveness analysis, we conclude that SCR is cost effective for all units of the SJGS.

Although we generally regard the visibility modeling analyses performed by NMED to be of high quality, we noted some minor issues we wished to rectify in order to address consistency with modeling guidance we have provided to the states. We remodeled the visibility impacts of the SJGS using revised emission estimates and meteorology results from the regulatory version of the CALPUFF and CALMET models. As detailed in the TSD, we utilized a different approach based on the best current information from the Electric Power Research Institute (EPRI) [26] to estimate the sulfuric acid released from combustion in the boiler for all scenarios and for operation of the SCR, assuming a 0.5% SO_2 to SO_3 conversion efficiency [27] of the SCR catalyst (compared to a 1% conversion assumed by NMED). We determined that the SCR could achieve an emission rate of 0.05 lb NO_X/MMBtu and included this emission rate in modeling the SCR control scenario (compared to 0.07 lb NO_X/MMBtu assumed by NMED). We modeled a revised baseline with the SO_2 emissions lowered to the BART presumptive limit of 0.15 lb/MMBtu that was assumed by the WRAP for regional photochemical visibility modeling to demonstrate reasonable progress towards natural visibility conditions. Finally, modeling was performed utilizing both the monthly variable background NH_3 concentration used by NMED and the default background NH_3 concentration of 1.0 ppb to evaluate the sensitivity of the results to these assumptions. Visibility impairment from our modeled pollutant concentrations were calculated using both the original IMPROVE equation (Method 6) used by NMED and the revised IMPROVE equation (Method 8) to calculate visibility impairment from the modeled pollutant concentrations.

As Table 8 indicates, in considering the visibility impacts associated with the use of SCR, we focused on the 98th percentile of modeled results to avoid giving undue weight to any extreme results.[28] The results are presented as the visibility impacts from SJGS and the associated changes in visibility at each Class I area within 300 kilometers of the facility resulting from the use of SCR. These results employ our revised baseline, a 1 ppb background NH_3 concentration assumption, our revised SO_2 to SO_3 conversion calculation, and the new IMPROVE equation (Method 8). The other methods that we utilized in our sensitivity modeling approaches using Method 6 and/or the variable NH_3 are documented in the TSD.

TABLE 8—EPA MODELED MAXIMUM IMPACTS OF THE 98TH PERCENTILE DELTA-dv IMPACTS FROM 2001–2003

Class I area	Distance to SJGS (km)	Baseline visibility impact (Δdv)	Visibility impact with SCR (Δdv)	Visibility improvement with SCR (Δdv)
Arches	222	3.50	1.12	2.38
Bandelier Wilderness	210	1.39	0.48	0.91
Black Canyon of the Gunnison Wilderness	203	1.41	0.42	0.99
Canyonlands	170	4.64	1.53	3.11
Capitol Reef	232	2.38	0.82	1.56
Grand Canyon	285	0.93	0.33	0.60
Great Sand Dunes National Monument	269	1.53	0.49	1.04
La Garita Wilderness	169	1.93	0.57	1.36
Maroon Bells Snowmass Wilderness	271	0.70	0.28	0.42
Mesa Verde	40	5.15	2.27	2.88
Pecos Wilderness	248	1.27	0.47	0.80
Petrified Forest	213	0.52	0.21	0.31
San Pedro Parks Wilderness	155	2.20	0.74	1.46
West Elk Wilderness	216	1.59	0.45	1.14
Weminuche Wilderness	98	2.92	0.87	2.05
Wheeler Peak Wilderness	258	1.12	0.44	0.68
Total Delta dv	....	33.18	11.48	21.69

As can be seen from Table 8, our visibility modeling indicates that SCR NO_X control offers visibility improvement at every one of the 16 Class I areas and significant visibility improvement at the overwhelming majority of areas. Therefore, after having identified all available retrofittable NO_X control technologies, eliminated those that were not technically feasible, evaluated the NO_X control effectiveness of those remaining, evaluated the impacts and having documented the results, we propose that NO_X BART for all the units of the SJGS is SCR with a 30 day rolling average of 0.05 lbs/MMBtu.

In addition, our visibility analysis relied in part on estimates of H_2SO_4 mist emissions. The amount of H_2SO_4 emissions depends, in part, on proper design and operation of the SCR unit. Therefore, we believe it is appropriate to set emission limits for H_2SO_4. We believe that our estimates of these emissions are appropriate based on the use of low reactivity catalyst that will reduce the rate of SO_2 to SO_3 conversion. To ensure these levels are met, we are proposing that emissions of H_2SO_4 be limited to 1.06×10^{-4} lb/MMBtu for each unit. These emission limits are based on the most current information from the Electric Power Research Institute (EPRI), information on the sulfur content of the coal, and assuming a maximum of 0.5% SO_2 to SO_3 conversion efficiency of the SCR catalyst. We note that there is some potential variation in the methodologies

[26] Electric Power Research Institute, Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, 1016384 Technical Update, March 2008.

[27] Emails between Anita Lee, EPA Region 9 and Anthony C. Favale P.E., Director—SCR Products, Hitachi Power Systems America, Ltd. Favale: "Catalyst development has progressed over the last few years to the point that an initial SO_2 conversion rate of 0.5% can be guaranteed with 80 to 90% NO_X reduction."

[28] *See* 70 FR at 39,121.

and the assumptions used method for calculating H_2SO_4 emissions. The assumptions associated with our calculation are discussed further in the TSD. We are soliciting comment on setting the emission limit in the range between our proposed limit of 1.06 x 10^{-4} lb/MMBtu and an upper range of sulfuric acid mist emissions of 7.87 x 10^{-4} lb/MMBtu.[29] Comments on our proposed H_2SO_4 limit and alternative limits should include consideration of the use of a low conversion rate SCR catalyst and be sufficiently justified.

As there are no continuous emission monitoring techniques for H_2SO_4 mist, we are proposing that compliance be based on an hourly average, confirmed by annual stack testing using EPA Test Method 8A (CTM–013).[30] We note that our proposed limits challenge the detection limits of the test method. We solicit comment on this issue, including suggestions for test methods that will better measure these low concentrations and other approaches to determine continuous compliance.

Similarly, our visibility analysis also relied in part on estimates of ammonia (NH_3) slip, emissions of NH_3 that pass through the SCR. NH_3 contribute to visibility impairment. Limiting NH_3 emissions depends on proper design and operation of the SCR. Therefore, we are proposing to set a limit to minimize the contribution of NH_3 to visibility impairment. We are proposing that emissions of NH_3 be limited to 2.0 parts per million volume dry (ppmvd), adjusted to 6 percent oxygen for each of the four SJGS units.[31] We are also soliciting comment on setting this limit in the range of 2–6 ppmvd, adjusted to 6 percent oxygen. Comments on our proposed limit and alternative limits should consider visibility impairment. Compliance will be based on an hourly average confirmed by an initial performance test using EPA Conditional Test Method 27 (40 CFR 51, Appendix M). We are also proposing that a CEM for NH_3 be installed and operated. We solicit comment on other approaches to determine continuous compliance.

As we note above in section II.B.3, the RHR requires that BART controls must be installed and in operation as expeditiously as practicable, but no later than five (5) years after the date of our approval of the RH SIP. 40 CFR 51.308(e)(1)(iv). Based on the retrofit of other SCR installations we have reviewed, we find that three (3) years from the date our final determination becomes effective is a conservative and adequate estimate of time for the planning, engineering, installation, and start-up of these controls.[32] Many installations have been completed in much shorter times.[33] We solicit comment on alternative timeframes, up to five (5) years from the date our final determination becomes effective.

IV. Proposed Action

We are proposing to disapprove a portion of the SIP revision submitted by the State of New Mexico for the purpose of addressing the "good neighbor" provisions of the CAA section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the $PM_{2.5}$ NAAQS. We are proposing to disapprove the New Mexico Interstate Transport SIP provisions that address the requirement of section 110(a)(2)(D)(i)(II) that emissions from New Mexico sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. As a result of the proposed disapproval, we are also proposing a FIP to address the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility. With regard to whether emissions from New Mexico sources interfere with the visibility programs of other states, we are proposing to find that New Mexico sources, except the SJGS, are sufficiently controlled to eliminate interference with the visibility programs of other states, and for the SJGS source we are proposing to impose specific SO_2 and NO_X emissions limits that will eliminate such interstate interference. In addition, EPA is proposing the FIP to address the requirement for BART for NO_X for the SJGS.

Based on our evaluation we are proposing to find that the SJGS is subject to BART under section 40 CFR 51.309(d)(4), and/or 51.308(e). Our proposed NO_X controls for SJGS will partially address the BART requirements of the RH program. Specifically, we are proposing a FIP that imposes NO_X BART limits for the SJGS. Together, the reduction in NO_X from our proposed NO_X BART determination, and the proposed SO_2 emission limits will serve to ensure there are enforceable mechanisms in place to prevent New Mexico NO_X and SO_2 emissions from interfering with efforts to protect visibility in other states pursuant to the requirements of section 110(a)(2)(D)(i)(II) of the CAA.

For NO_X emissions, we are proposing to require the SJGS to meet an emission limit of 0.05 pounds per million British Thermal Units (lb/MMBtu) individually at Units 1, 2, 3, and 4. This NO_X limit is achievable by installing and operating SCR. For SO_2, we are proposing to require the SJGS to meet an emission limit of 0.15 lb/MMBtu. Both of these emission limits would be measured on the basis of a 30 day rolling average. We are also proposing hourly average emission limits of 1.06 x 10^{-4} lb/MMBtu for H_2SO_4 and 2.0 ppmvd, for NH_3, to minimize the contribution of these compounds to visibility impairment. Additionally, we are proposing monitoring, recordkeeping and reporting requirements to ensure compliance with emission limitations.

We also propose that compliance with the emission limits be within three (3) years of the effective date of our final rule. We solicit comments on alternative timeframes, up to five (5) years from the effective date our final rule.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This proposed action is not a "significant regulatory action" under the terms of Executive Order (EO) 12866, (58 FR 51735, October 4, 1993), and is therefore not subject to review under the Executive Order. This action proposes a source-specific FIP for the San Juan Power Generating Station (SJGS) in New Mexico.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Under the Paperwork Reduction Act, a "collection of information" is defined as a requirement for "answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *." 44 U.S.C. 3502(3)(A). Because the proposed FIP applies to a single facility, (SJGS), the Paperwork

[29] Upper range value is based on information from PNM's Toxics Release Inventory report and previous PNM calculations of the amount of additional H_2SO_4 from the installation and operation of SCR. For details on the derivation of this upper bound value, see the TSD.

[30] *http://www.epa.gov/ttn/emc/ctm/ctm-013.pdf.*

[31] PNM materials previously indicated that a 2 ppm ammonia slip limit would be appropriate for SCR at the Public Service Company of New Mexico Black and Veatch report titled: "San Juan Generating Station Best Available Retrofit Technology Analysis" Issue Date and Revision June 6, 2007, Final; Appendix B, page B–3.

[32] Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, Institute of Clean Air Companies, December 4, 2006, *available* at *http://www.icac.7 com/files/public/ICAC_NOx_Control_Installation_ Timing_120406.pdf; see also* Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073, October 2002, *available* at *http://www.epa.gov/clearskies/pdfs/ multi102902.pdf.*

[33] *Id.*

Reduction Act does not apply. *See* 5 CFR 1320(c).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. The FIP for SJGS being proposed today does not impose any new requirements on small entities. *See Mid-Tex Electric Cooperative, Inc.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985).

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted to inflation) in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a Federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any 1 year. In addition, this proposed rule does not contain a significant Federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This action merely prescribes EPA's action to address the State not fully meeting its obligation to prohibit emissions from interfering with other states measures to protect visibility. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this proposed rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), applies to any rule that: (1) is determined to be economically significant as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This proposed rule is not subject to Executive Order 13045 because it limits emissions of pollutants from an existing single stationary source. Because this proposed action only applies to a single existing source and is not a proposed rule of general applicability, it is not economically significant as defined under Executive Order 12866, and does not have a disproportionate effect on children. However, to the extent that the rule will limit emissions of NO_X and SO_2 the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards. This proposed rule would require all sources to meet the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement System (PBMS), part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to part 75; however, EPA periodically revises the test procedures set forth in part 75. When EPA revises the test procedures set forth in part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in part 75, EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under 40 CFR 75.66 before they are used.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed rule limits emissions of pollutants from a single stationary source, SJGS.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Visibility, Interstate transport of pollution, Regional haze, Best available control technology.

Dated: December 20, 2010.

Samuel J. Coleman,

Acting Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

2. Add § 52.1628 to read as follows:

§ 52.1628 Interstate pollutant transport and regional haze provisions; What are the FIP requirements for San Juan Generating Station emissions affecting visibility?

(a) *Applicability.* The provisions of this section shall apply to each owner or operator of the coal burning equipment designated as Units 1, 2, 3, or 4 at the San Juan Generating Station in San Juan County, New Mexico (the plant).

(b) *Compliance dates.* Compliance with the requirements of this section is required upon the effective date of this rule unless otherwise indicated by compliance dates contained in specific provisions.

(c) *Definitions.* All terms used in this part but not defined herein shall have the meaning given them in the Clean Air Act and in parts 51 and 60 of this chapter. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight.

Air pollution control equipment includes baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants which would be emitted to the atmosphere.

Daily average means the arithmetic average of the hourly values measured in a 24-hour period.

Heat input means heat derived from combustion of fuel in a Unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR part 75.

Owner or Operator means any person who owns, leases, operates, controls, or supervises the plant or any of the coal burning equipment designated as Units 1, 2, 3, or 4 at the plant.

Oxides of nitrogen (NO_X) means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in 40 CFR part 60.

Regional Administrator means the Regional Administrator of EPA Region 6 or his/her authorized representative.

(d) *Emissions limitations and control measures.* (1) Within 180 days of the effective date of this paragraph (d), the owner or operator shall submit a plan to the Regional Administrator that identifies the air pollution control equipment and schedule for complying with paragraph (d) of this section. The owner or operator shall submit amendments to the plan to the Regional Administrator as changes occur. The NO_X and SO_2 limits shall be effective no later than 3 years after the effective date of this rule. No owner or operator shall discharge or cause the discharge of NO_X or SO_2 into the atmosphere from Units 1, 2, 3 and 4 in excess of the limits for these pollutants.

(2) *NO_X emission limit.* The NO_X limit for each unit in the plant, expressed as nitrogen dioxide (NO_2), shall be 0.05 pounds per million British thermal

units (lb/MMBtu) as averaged over a rolling 30 calendar day period. For each unit, NO_X emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of NO_X. For each unit, heat input for each calendar day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each day the thirty-day rolling average for a unit shall be determined by adding together the pounds of NO_X from that day and the preceding 29 days and dividing the total pounds of NO_X by the sum of the heat input during the same 30-day period. The result shall be the 30-day rolling average in terms of lb/MMBtu emissions of NO_X. If a valid NO_X pounds per hour or heat input is not available for any hour for a unit, that heat input and NO_X pounds per hour shall not be used in the calculation of the 30-day rolling average for NO_X.

(3) *SO_2 emission limit.* The sulfur dioxide emission limit for each unit shall be 0.15 lb/MMBtu as averaged over a rolling 30-calendar-day period. For each unit, SO_2 emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of sulfur dioxide. For each unit, heat input for each calendar day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each day the thirty-day rolling average shall be determined by adding together pounds of sulfur dioxide from that day and the preceding 29 days and dividing the total pounds of sulfur dioxide by the sum of the heat input during the same 30-day period. The results shall be the 30-day rolling average for lb/MMBtu emissions of SO_2. If a valid SO_2 pounds per hour or heat input is not available for any hour for a unit, that heat input and SO2 pounds per hour shall not be used in the calculation of the 30-day rolling average for SO_2.

(4) H_2SO_4 emission limit: Emissions of H_2SO_4 from each unit shall be limited to 1.06×10^{-4} lb/MMBtu on an hourly basis.

(5) Ammonia emission limit: Emissions of ammonia (NH_3) from each unit will be limited to 2.0 parts per million by volume, dry (ppmvd), adjusted to 6 percent oxygen, on an hourly average basis.

(e) *Testing and monitoring.* (1) On and after the effective date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for NO_X, SO_2, and NH_3 on Units 1, 2, 3, and 4 in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and Appendix B of Part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limits for NO_X, SO_2 and NH_3 shall be determined by using data from a CEMS.

(2) Continuous emissions monitoring shall apply during all periods of operation of the coal burning equipment, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2, NO_X, NH_3 and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid SO_2 pounds per hour, NO_X pounds per hour, SO_2 pounds per million Btu emission data, NO_X pounds per million Btu emission data, or NH_3 ppmvd data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive boiler operating days.

(3) Emissions of H_2SO_4 shall be measured within 180 days of start up of the NO_X control device and annually thereafter using EPA Test Method 8A (CTM–013).

(4) Emissions of ammonia shall be measured within 180 days of startup of the NO_X control device using EPA Conditional Test Method 27.

(5) The facility shall install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3.

(f) *Reporting and recordkeeping requirements.* Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Planning and Permitting Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6PD, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. For each unit subject to the emissions limitation in this section and upon completion of the installation of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For each emissions limit in this section, comply with the notification and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(2) For each day, provide the total NO_X and SO_2 emitted that day by each emission unit. For any hours on any unit where data for hourly pounds or heat input is missing, identify the unit number and monitoring device that did not produce valid data that caused the missing hour.

(g) *Equipment operations.* At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the Plant including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the Plant.

(h) *Enforcement.* (1) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the Plant would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(2) Emissions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit.

[FR Doc. 2010–33106 Filed 1–4–11; 8:45 am]

BILLING CODE 6560–50–P

EXHIBIT 2

SJCA, et al, April 4, 2001 comments to EPA on EPA Docket No. EPA-R06-OAR-2010-0846

SAN JUAN CITIZENS ALLIANCE
NATIONAL PARKS CONSERVATION ASSOCIATION
WILDEARTH GUARDIANS
COLORADO ENVIRONMENTAL COALITION
DINE CARE
DOODA (NO) DESERT ROCK
POWDER RIVER BASIN RESOURCE COUNCIL
SEVIER CITIZENS FOR CLEAN AIR & WATER
WESTERN COLORADO CONGRESS
SIERRA CLUB

April 4, 2011

By Email: donaldson.guy@epa.gov

Mr. Guy Donaldson, Chief,
Air Planning Section (6PD–L),
Environmental Protection Agency, 1445
Ross Avenue, Suite 1200, Dallas, Texas
75202–2733.

RE: EPA Docket No. EPA-RO6-OAR-2010-0846

Dear Mr. Donaldson:

The undersigned conservation organizations submit these comments on the Environmental Protection Agency's ("EPA") proposed Federal Implementation Plan ("FIP) for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination for San Juan Generating Station ("SJGS") under Section 110 of the Clean Air Act for the State of New Mexico published January 5, 2011 in the Federal Register at 76 Fed. Reg. 491 ("proposed rule" or "FIP"). The undersigned organizations represent thousands of New Mexicans and people throughout the nation that care deeply about protecting the air quality in our national parks and wilderness areas in New Mexico, the Intermountain West, and the Colorado plateau. We support EPA in proposing a FIP that will control substantial quantities of haze-causing pollutants from SJGS, however we encourage the Agency to revise, in accordance with the comments below, and require further reductions in emissions and otherwise advance measures that will improve intra-state, inter-state, and regional visibility as required by the Clean Air Act's ("CAA") regional haze program and Section 110 of the CAA.

We also support comments submitted by the National Park Service ("NPS") supporting installation of selective catalytic reduction ("SCR") for NOx control as the Best Available Retrofit Technology ("BART") for the SJGS. NPS's March 31, 2011 comments are attached hereto. We likewise support NPS's conclusion that SCR is cost-effective at SJGS. Finally, we also support NPS's letter to the State of New Mexico concluding that selective non-catalytic reduction ("SNCR") does not constitute BART for NOx control at SCR. NPS's March 31, 2011 letter to New Mexico is also attached hereto.

BACKGROUND

The requirements of the Clean Air Act

Congress declared as the national goal, the "prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. §7491(a)(1). "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities." 42 U.S.C. §7491(g)(3). Congress adopted the visibility protection program to protect the "intrinsic beauty and historical and archeological treasures" of specific public lands.[1] To protect these treasures, the regional haze program establishes a regulatory floor and requires states to design and implement programs at least as stringent as the national floor to curb haze-causing emissions located within their jurisdictions. In order to meet this goal, a state is required to design an implementation plan to reduce, and ultimately eliminate, haze from air pollution sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment for any protected area located within or beyond that state's boundaries. In creating and implementing the plan, a state has an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from some of its oldest and most polluting facilities.

As noted in the proposed rule, the CAA requires also each state to develop a plan that provides for the implementation, maintenance, and enforcement of the National Ambient Air Quality Standards ("NAAQS"). CAA section 110(a). EPA's NAAQS address six criteria pollutants: carbon monoxide, nitrogen dioxide, ozone, lead, particulate matter, and sulfur dioxide. States must develop State Implementation Plans ("SIPs) describing how the NAAQS will be met within each state. Another important aspect of a SIP is to ensure that emissions from within a state do not adversely impact ambient air in other states through the interstate transport of pollutants. CAA section 110(a)(2)(D)(i). States are required to periodically update or revise SIPs. *See* CAA section 110(a)(1). One such circumstance is the promulgation of a new or revised NAAQS. *Id.* Each state must submit these revisions to EPA for approval and incorporation into the federally-enforceable SIP. If a State fails to make a required SIP submittal or if EPA finds that the State's submittal is incomplete or unapprovable, then EPA must promulgate a FIP to fill this regulatory gap. CAA section 110(c)(1).

In September 2007, New Mexico submitted an Interstate Transport SIP to address

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[1]*See* H.R. REP. NO. 95-294, at 203–04 (1977).

the 1997 8-hour ozone and 1997 PM2.5 NAAQS. The SIP submission made by New Mexico anticipated the timely submission of a substantive regional haze SIP submission as the means of meeting the requirements of section 110(a)(2)(D)(i)(II) of the CAA. New Mexico has yet to submit such a regional haze SIP. In addition, New Mexico has not revised its submission to address the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility by any alternative means. New Mexico's SIP must have adequate provisions to prohibit emissions from adversely affecting another state's air quality through interstate transport. New Mexico's Interstate Transport SIP provisions fail to comply with section 110(a)(2)(D)(i)(II) requiring that emissions from New Mexico sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility.

By December 17, 2007, each State with one or more Class I Federal areas was also required to submit a regional haze SIP that included goals that provide for reasonable progress towards achieving natural visibility conditions. 40 C.F.R. 51.308(d)(1). EPA previously found that New Mexico had failed to submit a complete regional haze SIP by December 17, 2007. 74 Fed. Reg. 2392 (January 15, 2009). This finding started a two-year clock for the promulgation of a regional haze FIP by EPA or the approval of a complete regional haze SIP from New Mexico. CAA §110(c)(1).

To address the shortcomings of New Mexico's SIP and ensure the air quality standards are protective of public health and Class I area visibility, EPA proposes and must promulgate a FIP for the purpose of addressing the "good neighbor" requirements of section 110(a)(2)(D)(i) of the CAA for the 1997 8-hour ozone NAAQS and the 1997 fine particulate matter (PM2.5) NAAQS and also to meet the requirements under the regional haze program for BART at San Juan Generating Station.

VISIBILITY, PUBLIC HEALTH, ECOLOGY, AND ECONOMICS

Visibility and regional haze impacts

Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances, color, and geologic formations. While some haze-causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze-forming pollutants, including sulfur dioxide (SO2), nitrogen oxides (NOx), particulate matter (PM), volatile organic compounds (VOCs), sulfuric acid (H_2SO_4) and ammonia (NH3), contribute directly to haze or form haze after breaking down in the atmosphere. These air pollutants contribute to the deterioration of air quality and reduced visibility in our national parks and wilderness areas. Visibility impairment is measured in deciviews, which is a measure of the perceptible change in visibility. The higher a deciview value is, the worse the visibility impairment. Emissions from coal plants, such as the SJGS can travel long distances in the atmosphere and contribute to interstate visibility impairment in national parks beyond the borders of state boundaries. As noted in the proposed rule, "NOx and SO2 are significant contributors to visibility impairment in and around New Mexico. As the Four Corners Task Force notes, '[r]eduction of NOx is particularly important to improve visibility at Mesa Verde

National Park, which is 43 km away from SJGS. . ..[V]isibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased...'"

Public health impacts

The same pollutants that contribute to visibility impairment also harm public health. The fine particulates that cause regional haze, PM2.5, are a major public health concern because they can be inhaled deep into the lungs. Fine particulate can cause decreased lung function, aggravate asthma, and premature death in people with heart or lung disease. NOx and VOCs can also be precursors to ground level ozone, or smog. Ground level ozone is associated with respiratory diseases, asthma attacks, and decreased lung function.[2] Ozone concentrations in parks in the Four Corners region approach the current health standards,[3] and likely violate anticipated lower standards.[4] In fact, ozone levels in many parts of New Mexico, Colorado and Utah are already in the range of ozone levels deemed to be harmful to human health.[5]

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[2] *See* http://www.nature.nps.gov/stats/index.cfm.

[3] Monitors in the Four Corners region have registered ozone concentrations within 5% of the level considered to be a violation of the ozone NAAQS. As of 2008, the fourth highest ozone concentrations in Zion and Canyonlands national parks each year have averaged 72 ppb and 71 ppb respectively. Mesa Verde National Park and Petrified Forest National Monument each had 3-year averages of the fourth high ozone concentrations of 71 ppb as of 2008. Monitors in Grand Canyon National Park and Farmington, New Mexico had a 3-year average of the fourth highest ozone concentration equal to 70 ppb as of 2008.

[4] On September 16, 2009, EPA announced it will reconsider both primary and secondary ozone standards to ensure they are scientifically sound and protective of human health and welfare. (http://www.epa.gov/groundlevelozone). EPA will be reviewing the science that guided the 2008 decision as well as the findings of EPA's independent Clean Air Scientific Advisory Committee ("CASAC") which unanimously recommended decreasing the primary standard to within the range of 0.060–0.070 ppm.

[5] See Clean Air Scientific Advisory Committee correspondence with EPA Administrator Stephen Johnson (Oct. 24, 2006) ("Clean Air Scientific Advisory Committee's (CASAC) Peer Review of the Agency's 2nd Draft Ozone Staff Paper"). CASAC found that elevated ozone concentrations are associated with "an increase in school absenteeism; increases in respiratory hospital emergency department visits among asthmatics and patients with other respiratory diseases; an increase in hospitalizations for respiratory illnesses; an increase in symptoms associated with adverse health effects, including chest tightness and medication usage; and an increase in mortality (non-accidental, cardiorespiratory deaths) reported at exposure levels well below the current standard."

According to U.S. Environmental Protection Agency (EPA), the total annual cost of implementing the Regional Haze Rule will range from 1.4 – 1.5 billion dollars.[6] However, based on the attendant reductions in air pollution, EPA determined that in 2015, enforcement of the Regional Haze Rule will provide health benefits valued at $8.4 – $9.8 billion annually – preventing 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days every year.[7]

Ecosystem impacts

These same haze-causing emissions also harm terrestrial and aquatic plants and animals, soil health, and moving and stationary waterbodies – entire ecosystems – by contributing to acid rain, ozone formation, and nitrogen deposition. Nitrogen deposition, caused by wet and dry deposition of nitrates derived from NOx emissions, causes well known adverse impacts on ecological systems. Scientific investigations have already demonstrated that nitrogen is saturating the soil, plants and water of Rocky Mountain National Park at levels at least twice the "critical load" the ecosystem can tolerate.[8] According to EPA, "[a]cid rain causes acidification of lakes and streams and contributes to the damage of trees at high elevations (for example, red spruce trees above 2,000 feet) and many sensitive forest soils. In addition, acid rain accelerates the decay of building materials and paints, including irreplaceable buildings, statues, and sculptures that are part of our nation's cultural heritage."[9]

Further, haze-causing pollutants are precursors to ozone. Ground-level ozone formation impacts plants and ecosystems by: "interfering with the ability of sensitive plants to produce and store food, making them more susceptible to certain diseases,

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Moreover, a recent study in the New England Journal of Medicine provides confirmation that that long-term exposure to ozone increases the risk of death from respiratory causes. Jerrett, Michael et al., "Long Term Ozone Exposure and Mortality," NE J Medicine 2009; 360, 1085-1095. In a long-term study of nearly 500,000 participants, the study found a 4% increase in death for respiratory causes for every 10-ppb increase in exposure to ozone. The risk of dying from respiratory causes in the highest-ozone areas was nearly three times that in the lowest-exposure areas.

[6]EPA, Fact Sheet, *Final Regional Haze Regulations for Protection of Visibility in National Parks and Wilderness Areas* (June 2, 1999) at http://www.epa.gov/visibility/fs_2005_6_15.html

[7]http://yosemite.epa.gov/opa/admpress.nsf/a4a961970f783d3a85257359003d480d/a7f12fefcb64426885257022004fbd26!OpenDocument.

[8]http://www.nature.nps.gov/air/permits/aris/romo/impacts.cfm

[9]http://www.epa.gov/acidrain/effects/index.html

insects, other pollutants, competition and harsh weather; damaging the leaves of trees and other plants, negatively impacting the appearance of urban vegetation, as well as vegetation in national parks and recreation areas; and reducing forest growth and crop yields, potentially impacting species diversity in ecosystems."[10]

Economic impacts

In rigorously addressing visibility and, more specifically, visibility-causing pollutants, New Mexico, the intermountain west and the Colorado plateau stand to reap significant benefits and avoid serious consequences. Visibility-causing pollutants have far-reaching impacts on local economies, human health, and the well-being of waterways, soils, plants, and wildlife – in other words, an entire population and ecosystems. Decreasing these pollutants will benefit all of these important areas of concern; failing to do so will cause or continue adverse impacts.

Tourism is critical to the economy of New Mexico and the Four Corners region. The national parks and landmarks potentially impacted by the SJGS include the Grand Canyon, Mesa Verde, Monument Valley, Canyon de Chelly, Petrified Forest, Grand Staircase Escalante, Bryce Canyon, Canyonlands, Arches, and Chaco Culture. The towns surrounding these parks, monuments and landmarks are economically dependent on excellent air quality. For example, Utah's five Class I areas, all of which are national parks, generate a significant portion of this sustainable tourism economy: in 2008, these areas were responsible for 5.7 million recreation visits, over $400 million in spending, and nearly 9,000 jobs.[11] Parks attract businesses and individuals to the local area, resulting in economic growth in areas near parks that is an average of 1 percent per year greater than statewide rates over the past three decades.[12] National parks also generate more than four dollars in value to the public for every tax dollar invested.[13]

Because of pollution, visitors to western parks now can only see around 60 miles away on bad days, where naturally they would be able to see double or triple that distance.[14] Studies have shown that visitors value clean air in our national parks, are able

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[10]http://www.epa.gov/glo/health.html

[11]National Park Visitor Spending and Payroll Impacts, 2008. Daniel J. Stynes, Michigan State University, October 2009.

[12]http://web4.msue.msu.edu/mgm2/parks/MGM2System2008.pdf.

[13]Hardner and Gullison, "The U.S. National Park System, An Economic Asset at Risk" (November 2006) [prepared for the National Parks Conservation Association].http://www.npca.org/park_assets/NPCA_Economic_Significance_Report.pdf

[14]*Id.*

to tell when it is hazy, and enjoy their visit less when haze is bad. Moreover, visitors are willing to alter their length of stay based on their perception of air quality.[15] Shorter park visits, or none at all, means less time and money spent in gateway communities.

An additional economic incentive behind protecting air quality is the necessary investment in pollution control technologies as they are a job-creating mechanism in itself. Each installation creates short-term construction jobs as well as permanent operations and management positions.

The regional haze program imposes a legal obligation on EPA where a state, such as New Mexico falls short in advancing a SIP that will abate the adverse visibility effects to which its haze causing facilities contribute. EPA must therefore act to restore visibility levels to their natural conditions as mandated by the Clean Air Act. In its proposed action, EPA has taken significant steps to prevent and remedy visibility impairment to the implicated Class I areas, however it must revise and improve the draft FIP to ensure adequate protection of these areas. A strong regional haze program will not only help protect and restore treasured landscapes and the economies that rely on them but also benefit public health and ecosystems. With this in mind, we offer the comments below for consideration by Region 6 and strongly encourage the Region to strengthen its regional haze plan.

The remainder of this comment letter will provide more specific comments on EPA's proposed rule.

<u>NOx Issues</u>

This section of the comment letter addresses NOx issues raise by the proposed rule.

1. A NOx Limit of 0.035 lb/mmbtu Is Technically Feasible

The EPA proposes a NOx limit of 0.05 lbs/mmbtu for the San Juan Generating Station ("SJGS") as BART. While this would significantly reduce NOx emissions from SJGS, and have a positive impact on visibility and public health, as explained below, a lower NOx limit of 0.035 lbs/mmbtu is not only technically feasible, but legally-required for SJGS under the Clean Air Act.

As the agency acknowledges in its proposed rule, the State of New Mexico "noted the potential for greater control rates as low as 0.03 lbs/mmbtu" for SJGS.76 Fed.Reg. at 499. This is consistent with the findings of Dr. Ron Sahu, in his attached comments. The facility's current NOx emissions are limited to 0.30 lbs/mmbtu, on a 30-day rolling average, under a 2005 consent decree entered into by PNM and Grand Canyon Trust, Sierra Club and the State of New Mexico. *Id.* at 497. And, as explained by the Technical Support Document ("TSD") for the proposed FIP, Selective Catalytic

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[15]http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewInd&lv=list.listByAlpha&r=231326&subtop=341

Reduction ("SCR") technologies "are routinely designed and have routinely achieved a NOx control efficiency of 90%." TSD at 30. Assuming a 90% removal efficiency, based on SJGS's current rate of emissions (under 0.30 lbs/mmbtu), modern SCR technology would bring controlled emissions down to 0.03 lbs/mmbtu. As explained in his attached comments, Dr. Sahu proposes a 0.035 lbs/mmbtu limit, under a conservative approach that takes into account normal fluctuations in emission rates and control efficiency.

Despite the well-demonstrated and routine achievement of 90% removal, EPA's proposal inexplicably assumes a mere 83% NOx removal rate for SCR at SJGS. While it is true that SJGS obtains its coal from a single source that carries a unique combination of characteristics, as Dr. Sahu explains, there is no specific characteristic of this coal that prevents a 90% removal efficiency that is routinely achieved by modern SCR technologies throughout the country.

Because 90% NOx removal is the well-accepted, current industry standard for SCR technology, it is EPA's burden to show that "specific circumstances preclude its application" to SJGS. 40 C.F.R Part 51, Appendix Y. Aside from PNM's hypothetical concerns about the coal supply that Dr. Sahu shows to be unfounded, the EPA provides no specific technical reason to support its claim that a 90% removal efficiency for SCR at SJGS is infeasible. For example, PNM claims that SCR efficiency is constrained by the creation of excess sulfuric acid mist, yet, as Dr. Sahu explains, this claim is belied by the low sulfur content (less than 1%) in SJGS's coal supply. In fact, when EPA specifically asked why SCR would not be able to achieve a 90% NOx removal at SJGS, PNM simply sidestepped the issue and urged the EPA to instead shift its focus on outlet emission rates.[16] In short, the record does not support the claim that 90% removal efficiency is infeasible.

By contrast, Dr. Sahu provides a technical basis, including support from major catalyst vendors, to show that 90% removal efficiency is feasible and should be required. Vendor validation is a useful factor in determining feasibility because, according to the BART Guidelines, "[v]endor guarantees may provide an indication of ... the technical feasibility of a control technique . . . ." 40 C.F.R Part 51, Appendix Y. In support of his expert opinion, Dr. Sahu also provides evidence showing that an emission rate of 0.035 lbs/mmbtu is being achieved at other units, even without a permit limit requiring it. Furthermore, as Dr. Sahu explains, in three years (when SJGS will be required to meet the new limit under EPA's proposal), SCR technology will improve to even greater levels of efficiency than exist today, thereby making a limit of 0.035lb/mmbtu not only reasonable, but also a modest standard.

2. A NOx Limit of 0.035 lbs/mmbtu Is Cost-Effective

According to Dr. Sahu's expert opinion and accompanying analysis, achieving a higher SCR efficiency than currently proposed only requires a relatively small, incremental cost. More specifically, to achieve a NOx rate of 0.035 lbs/mmbtu at SJGS,

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[16] *See* EPA-R06-OAR-2010-0846-0017.27.pdf (in the docket for the proposed rule).

Dr. Sahu estimates the following cost-effectiveness values: \$1,808/ton (Unit 1), \$1, 879/ton (Unit 2), \$1,485/ton (Unit 3) and \$1,453/ton (Unit 4). Because these additional costs would be so low, especially as compared to the benefit they would produce, a limit of 0.035 lbs/mmbtu minimally impacts the cost-effectiveness analysis and remains well below the accepted cost-effectiveness thresholds for BART. In fact, as Dr. Sahu explains in his attached comments, these cost estimates are even below the values presented by EPA in the preamble to its proposed rule. In short, cost is no barrier to implementation of a 0.035 lbs/mmbtu emission limit for NOx.

SO2 Issues

This section of the comment letter addresses SO2 issues raised by the proposed rule.

1. EPA should issue a Section 308 FIP for SO2 at the SJGS.

To date, the State of New Mexico has yet to submit a final regional haze SIP for EPA's approval. This includes New Mexico's failure to submit either a section 309 SIP, or an SO2 BART determination for SJGS under section 308. The EPA was under a legal duty to issue a final regional haze SIP for New Mexico by January 15, 2011. To date, EPA has failed to approve a regional haze SIP for New Mexico because the state has failed to file such a SIP with EPA.

Given New Mexico's failure to submit a timely and complete regional haze SIP to the EPA for approval, EPA now has a duty to issue a regional haze federal implementation plan ("FIP") for New Mexico. Subject to the comments herein, EPA's Section 110 FIP satisfies EPA's procedural BART obligations at the SJGS for NOx. However, EPA must still satisfy its regional haze obligations at SJGS with regard to SO2. Accordingly, the undersigned request that EPA promptly issue a Section 308 FIP for SO2, including an SO2 BART determination for the SJGS.

2. EPA's reliance on the presumptive SO2 limit of 0.15 lbs/mmbtu is improper.

In its Section 110 FIP, EPA states, "[a]s we discuss above, there are no federally enforceable limits that restrict the SJGS's SO2 emissions at 0.15 lbs/mmbtu, the rate assumed by the WRAP in its modeling. Therefore, as part of this action, we are proposing to impose an SO2 emission rate of 0.15 lbs/mmbtu on a 30 day rolling average for units 1, 2, 3, and 4 of the SJGS. By imposing this limit through this action, we will insure that SO2 emissions from this source are not interfering with the visibility programs of other states." For the reasons stated below, an SO2 emission rate of 0.15 lbs/mmbtu on a 30 day rolling average is not appropriate and does not insure that SO2 emissions from SJGS will not interfere with visibility in New Mexico or other states.

First, an SO2 emission rate of 0.15lbs/mmbtu does not reflect the level of emissions reductions achievable under BART. EPA's proposed rule admits this fact by stating, "[w]e are not making a finding that this SO2 emission limit satisfies BART for SO2." As noted above, given the State of New Mexico's failure to submit a final regional haze SIP, EPA is now legally required to issue such a FIP BART determination under Section 308.

Moreover, EPA's proposed SO2 emission limit does not reflect the level achievable through existing controls. For example, Ravi K. Srivastava of EPA's own Research Triangle Park has issued a technical paper entitled "Controlling SO2 emissions: A Review of Technologies" (EPA/600/R-00/093 November 2000). In the paper, EPA concludes that "wet limestone systems have been designed for high levels of SO2 removal, up to 98 percent." This same level of SO2 removal should be required at the SJGS as part of this rulemaking (or as part of an EPA SO2 BART FIP for SJGS).

Another example of an appropriate BART emission limit for SO2 at the SJGS is the emission limit imposed on the Desert Rock coal plant by EPA Region 9. EPA Region 9's issued a Prevention of Significant Deterioration ("PSD") permit for the Desert Rock Energy Facility to be located adjacent to the Navajo mine on Navajo lands in northwest New Mexico. Desert Rock would have used the same coal as the SJGS—coal from the Navajo mine. In conducting a BACT determination, EPA Region 9 determined that Desert Rock could meet an SO2 emission limit of 0.06 lbs/mmbtu on a 24 hour block-average basis using Navajo mine coal.[17] The Desert Rock coal plant would use not only the same coal as SJGS, but also the same type of SO2 air pollution control technologies as the SJGS—baghouses and wet scrubbers. Thus, instead of issuing an SO2 emission limit three times what is achievable with existing technology, the EPA should issue an SO2 BART determination requiring the SJGS to meet a limit of 0.06 lbs/mmbtu on a 24 hour block average at each of the four units.

EPA's proposed rulemaking also fails to establish a legally defensible administrative record for setting an SO2 emission rate of 0.15lbs/mmbtu. EPA's basis for this emission limit is that it was "the rate assumed by WRAP in its modeling." However, EPA's Section 110 FIP fails to provide further technical information supporting its choice of 0.15lbs/mmbtu as the appropriate emission limit for SO2 at SJGS.

A review of recent SO2 emission data from SJGS proves that each unit is currently emitting SO2 at emission rates significantly lower than 0.15lbs/mmbtu. More specifically, attached hereto is SO2 emission data from 2009 at the SJGS. The table below shows the average of all 30 day rolling average SO2 emissions for each unit at SJGS in 2009:

Unit	SO2 30 day rolling average (lbs/mmbtu)
Unit 1	0.069
Unit 2	0.091
Unit 3	0.093
Unit 4	0.084

[17]*See*, *http://www.regulations.gov/#!docketDetail;rpp=10;po=60;D=EPA-R09-OAR-2007-1110*.

Thus, the data and table above reveal that SJGS's recent SO2 emissions are much lower than EPA proposes to establish in its Section 110 FIP. EPA's proposed SO2 emission limit of .15lbs/mmbtu could result in ***worse*** visibility impairment because it would authorize SJGS to emit significantly greater amounts of SO2 than it currently emits. Therefore, EPA's proposed SO2 emission rate of 0.15 lbs/mmbtu not only fails to "insure that SO2 emissions from this source are not interfering with the visibility programs of other states", it could make visibility impairment worse both within New Mexico, as well as in neighboring states. EPA's proposed rule states, " [w]e note an examination of the SJGS's actual emission rates based on emissions reported by our Clean Air Markets Division indicates units 1, 2, 3, and 4 of the SJGS are already meeting these SO2 emission limits." There is no rational basis for EPA to set SO2 emission rates in a Section 110 FIP that exceed the historic SO2 emission rates at SJGS. Thus, if EPA insists on setting a non-BART SO2 limit in its Section 110 FIP, we request that EPA set unit-specific limits at least consistent with the recent historic SO2 emission identified in the table above. However, as noted above, since EPA is not making a BART determination for SO2 in this proposed rule, we request that EPA to issue formal SO2 BART determinations for each unit at SJGS under a Section 308 FIP.

3. The Proposed Rule Illegally Sidesteps a BART Determination for SO2 By Relying On A Yet-To Be Proposed 309 SIP

In declining to find that its asserted SO2 limits satisfy BART, EPA's proposal improperly relies on a regional haze trading program under 40 C.F.R § 51.309 that does not yet exist. 76 Fed. Reg. at 498. Putting aside EPA's legal obligation to make a formal BART determination in its proposed FIP at this time (40 C.F.R § 51.308(e)), any emissions trading program that is proposed to replace a BART limit "must achieve greater reasonable progress than would be achieved through the installation and operation of BART." 40 C.F.R § 51.308(e)(2). Because EPA cannot make the required demonstration that that New Mexico's future, theoretical trading program will be "better than BART," EPA is illegally sidestepping its current BART obligations under 40 C.F.R § 51.308 (e)(2)(i).

<u>Other pollutants</u>

For the reasons stated in EPA's proposed rule, we also fully support EPA setting emission limits for H_2SO_4 and ammonia at the SJGS, and the corresponding installation of CEMs to accurately document the continuous emission rate of these pollutants. We also request that EPA set BART emission limits for PM at SJGS in the final rule or as part of a regional haze FIP under section 308.

With regard to H_2SO_4, we support EPA's determination to set emission limits. We urge EPA to set the emission rate at the lowest rate of 1.06 x 10-4lb/MMBtu for each unit at the SJGS. We agree that this rate is supportable based on use of low reactivity catalyst and the most current information from the Electric Power Research Institute ("EPRI"). If continuous emission monitors are truly unavailable for this pollutant, we also urge EPA to require stack test monitoring for H_2SO_4 on a more frequent basis than annual monitoring. EPA should clarify in this final rule that the emission limit being set is being required under the regional haze program as part of a BART determination for the facility and must be complied with within 3 years of the date of the final rule. If EPA does not set BART limits in the final rule, it should conduct a BART analysis for H_2SO_4 in a Section 308 FIP.

With regard to ammonia, we also support EPA setting the lowest emission rate considered at the SJGS. NH3 emissions are important in that they react with SO2 and NOx to form ammonium sulfate and ammonium nitrate particles, which are very effective in impairing visibility. Thus, we support EPA setting the ammonia emission limit at the lower range of 2.0 parts per million. We also support requiring installation of CEMs to monitor this pollutant. EPA should also clarify in this final rule that the emission limit being set is being required under the regional haze program as part of a BART determination for the facility and must be complied with within 3 years of the date of the final rule. If EPA does not set BART limits in the final rule, it should conduct a BART analysis for ammonia in a Section 308 FIP.

With regard to PM, EPA did not set any emission limits in the proposed rule. We urge EPA to set BART emission limits for PM at SJGS either in the final rule, or as part of a regional haze FIP under section 308. PM is an important visibility impairing pollutant that must be controlled at the SGJS. Based on the reasoning and analysis in the November 20, 2009 comments submitted by the National Park Service for the Four Corners power plant BART determination, we urge EPA to likewise set a PM limit of 0.012 lb/mmbtu on a 6-hour block average, applicable to each unit individually, with compliance determined by PM CEMS. This limit is also supported by a 2008 report submitted by ENSR for the Four Corners BART determination.

We also urge EPA to follow the lead of Region 9 for the Four Corners power plant PM BART determination by setting a 10% opacity limit at each unit at SJGS to control PM emissions. Compliance with PM emission limit should likewise be required within three years of the final rule.

Timeframe for compliance

We fully support EPA's requirement that the emission limits be achieved within 3 years of the date of a final FIP. There is ample data supporting the fact that all emission control technology can be installed and operational within 3 years or less. However, it is unclear whether the 3-year timeframe is only intended to apply to EPA's BART determination for NOx, or whether the 3 year timeframe applies to all emission limits set by the FIP, which in addition to NOx includes SO2, H_2SO_4, PM and ammonia. We urge the EPA to clarify that the 3 year timeframe applies to all emission limits set in the FIP, including NOx, SO2, HH_2SO_4, PM and ammonia.

Startup/shutdown/malfunction

EPA's proposed rule states, "[e]missions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit." We request that EPA specifically include startups and shutdowns in this language making clear that any emission in excess of an applicable emission limit during any such event constitutes a violation of the applicable emission limit. We also request that EPA clarify that this provision applies to all pollutants controlled by this FIP, including, NOx, SO2, H_2SO_4, ammonia, and PM.

Thank you for the opportunity to submit comments on EPA's proposed Section 110 FIP for New Mexico. Please incorporate all comments herein contained and attachments into your final rule. We also ask that EPA promptly revise and finalize its final rule to ensure that visibility issues are quickly addressed at SJGS.

Sincerely,

Mike Eisenfeld
New Mexico Energy Coordinator
San Juan Citizens Alliance
108 North Behrend, Suite I
Farmington, New Mexico 87401
office 505 325-6724
cell 505 360-8994
meisenfeld@frontier.net

David Nimkin
Southwest Regional Director
National Parks Conservation Association
307 West 200 South
Suite 5000
Salt Lake City, Utah 84101
801 /521-0785
801/359-2367 fax
dnimkin@npca.org

Charlie Montgomery
Colorado Environmental Coalition
1536 Wynkoop St., Suite 5C
Denver, CO 80202
(303) 405-6707
charlie@ourcolorado.org

Lori Goodman
Dine CARE
10A Town Plaza, PMB 138
Durango, CO 81301
(970) 259-0199

kiyaani@frontier.net

Elouise Brown
Dooda (NO) Desert Rock
P.O. Box 7838
NewComb, NM 87455
(505) 947-6159
thebrownmachine@hotmail.com

Kevin Lind
Powder River Basin Resource Council
934 N. Main St.
Sheridan, WY 82801
(307) 672-5809
klind@powderriverbasin.org

Dick Cumiskey
Sevier Citizens for Clean Air & Water
P.O. Box 182
Richfield, UT 84754
(435) 527-4448
dickc@cut.net

Gretchen Nicholoff
Western Colorado Congress
P.O. Box 1931
Grand Junction, CO 81502
(970) 256-7650
gnicholoff@gmail.com

Jeremy Nichols
WildEarth Guardians
1536 Wynkoop, Suite 301
Denver, CO 80202
(303) 573-4898 x.1303
jnichols@wildearthguardians.org

Bill Corcoran
Sierra Club
3435 Wilshire Boulevard, Suite 660
Los Angles, CA 90010
(213) 387-6528 x.208
bill.corcoran@sierraclub.org

cc: Suma Peesapati, Earthjustice, 426 17th Street 6th Floor, Oakland, CA 94612-2820
John Barth, Attorney at Law, P.O. Box 409, Hygiene, CO 80533

EXHIBIT 3

Dr. Ranajit Sahu's April 4, 2001 comments to EPA on EPA Docket No. EPA-R06-OAR-2010-0846

Comments on the

Best Available Retrofit Technology (BART) Analysis

for

Public Service of New Mexico (PNM)'s San Juan Generating Station Units 1-4

as proposed by the

U.S. Environmental Protection Agency (EPA)

Report
by
Dr. Ranajit (Ron) Sahu, Ph. D.

April 4, 2011

Dr. Ranajit Sahu

A. Summary and Conclusion

I have been asked by counsel to provide technical comments on the proposed NOx Best Available Retrofit Technology (BART)[1] determination proposed by the EPA[2] for Units 1-4 at PNM's San Juan Generating Station (SJGS).

While I agree that the proposed BART level of 0.05 lb/MMBtu on a 30-day rolling average basis using Selective Catalytic Reduction (SCR) as the NOx control, is a step in the right direction from PNM's much less stringent proposals[3], it is my expert opinion that it is still flawed. I agree that SCR is the proper choice of NOx reduction technology; however, I disagree that 0.05 lb/MMBtu on a 30-day rolling average is a proper BART emission level, considering the current NOx emissions from these units and the current capabilities of SCR, as designed and demonstrated.[4] I show that the proper BART level should not exceed 0.035 lb/MMBtu on a 30-day rolling average basis.

A copy of my resume is provided in Attachment A.

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[1] EPA did not propose BART for SO2 in the proposed rulemaking, thus I am not providing technical comments on the proposed emission limit for SO2 in this analysis. Also, EPA has proposed, and I agree, with the proposals for the hourly emission limits for sulfuric acid mist (H2SO4) and ammonia (NH3), subject to the additional monitoring requested in the accompanying comments. My comments and recommendations for a revised NOx BART limit are consistent with these other limits as proposed by the EPA.

[2] 76 FR 492, January 5, 2011. EPA's proposal addresses interstate transport of pollution affecting visibility and the BART determination for New Mexico. Comments were initially due on March 7, 2011. The deadline for comments was later extended to April 4, 2011 (see 76 FR 12305, March 7, 2011.

[3] In this regard, I note that PNM and the state of New Mexico have provided additional proposals and analyses for NOx BART after the date of the EPA proposal. See http://www.nmenv.state.nm.us/aqb/reghaz/Regional-Haze_index.html. In these most recent proposals, which are up for adoption before the New Mexico Environmental Improvement Board (EIB), the state of New Mexico is urging the EIB to adopt a NOx BART level of 0.23 lb/MMBtu, using Selective Non-Catalytic Reduction (SNCR), a much less stringent level of control than EPA's already-lenient proposal. While I am not providing comments on this proposal, I urge the EPA to reject it if and when it is submitted to the EPA for consideration, likely after the close of the current comment period. It does not reflect BART from a regulatory perspective, it relies on inaccurate cost data to inflate the cost of installing SCR and it improperly addresses cost impacts on New Mexico electricity customers (not a BART factor), without any consideration of the benefits of reduced pollution on the very same customers and others who are affected by emissions from this plant.

[4] EPA's proposal reflects, by EPA's own admission, "…an approximately 83% reduction…" in NOx from SJGS's baseline NOx emissions. See 76 FR 493.

B. Introduction and Baseline Actual NOx at Units 1-4

The SJGS consists of four coal-fired generating units (hereafter Units 1-4 and associated support facilities. Each coal-fired unit burns pulverized coal from the adjacent San Juan mine and No. 2 diesel oil (for startup) in a boiler, and produces high-pressure steam which powers a steam turbine coupled with an electric generator. Units 1 and 2 are similar Foster Wheeler wall-fired design boilers and are rated at electrical outputs of 350 and 360 MW, respectively. Units 3 and 4 are similar Babcock and Wilcox opposed wall-fired boilers, with each have an electrical generation rating of 544 MW.[5]

In 2005, the operator of the SJGS, PNM entered into a consent decree with the Grand Canyon Trust, Sierra Club, and the New Mexico Environment Department (NMED) to reduce emissions of NOx, SO2, particulate matter and mercury. Among other requirements, the consent decree imposed a NOx emission restriction of 0.30 lb/MMBtu on a 30-day rolling average.

In developing these comments, I reviewed the 2009 and 2010 actual NOx emissions from Units 1-4, as submitted by the SJGS to the EPA under the Acid Rain program. That data is available at EPA's Clean Air Markets Division (CAMD) website.[6] I also reviewed daily emissions data for years 2009 and 2010. Except for a brief time period at the beginning of 2009 for Unit 2, all four units consistently met the consent decree NOx level of 0.30 lb/MMBtu. Table 1 in Attachment B provides this data. Table A below provides a summary of this data as well.

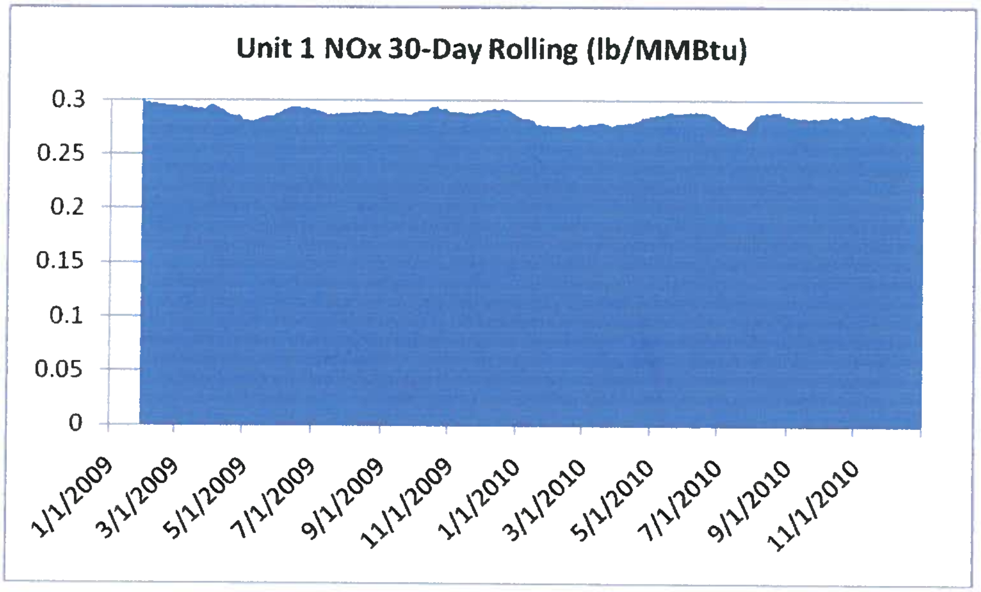
Table A – Summary of 2009/2010 30-day Rolling Average NOx (lb/MMBtu)

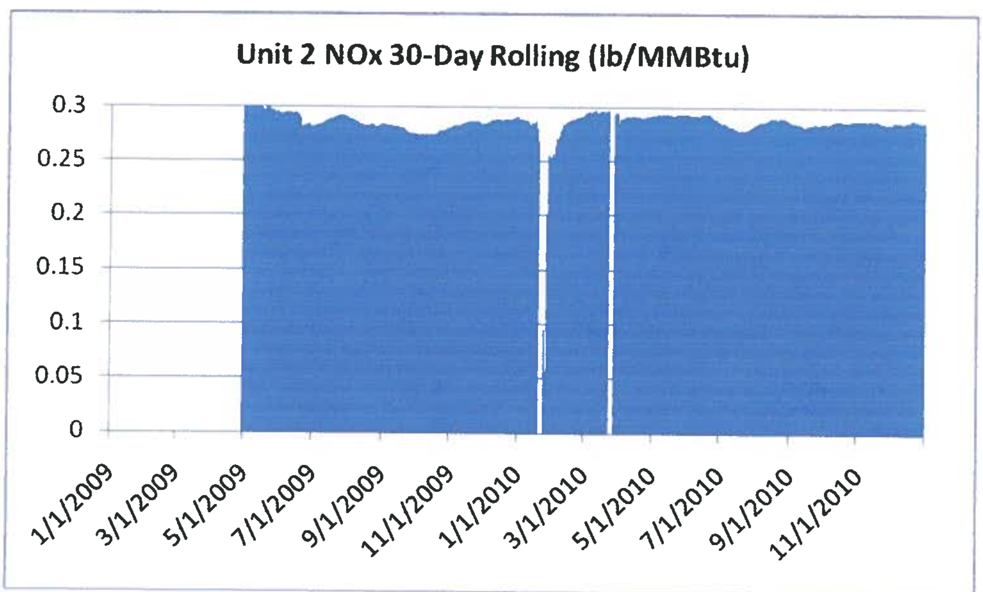
	UNIT 1	UNIT 2	UNIT 3	UNIT 4
Average	0.286	0.282	0.275	0.284
Max	0.299	0.314	0.303	0.306
StDev	0.006	0.035	0.023	0.007
StDev/Avg	0.019	0.124	0.082	0.026

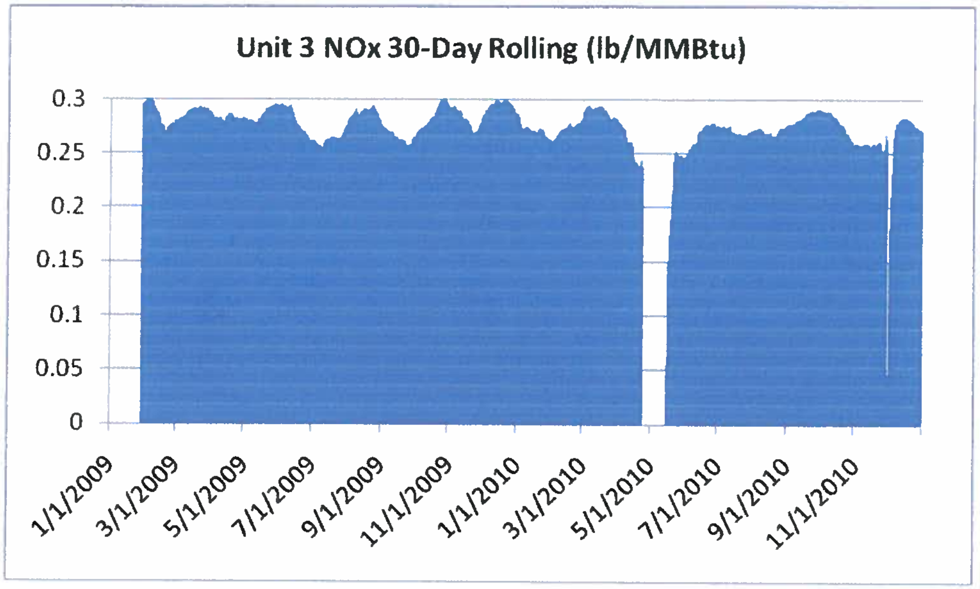
[5] Black and Veatch, PNM SJGS BART Analysis, June 6, 2007, Page A-2. EPA-R06-OAR-2010-0046-0013.8.pdf
[6] See www.epa.gov/airmarkets

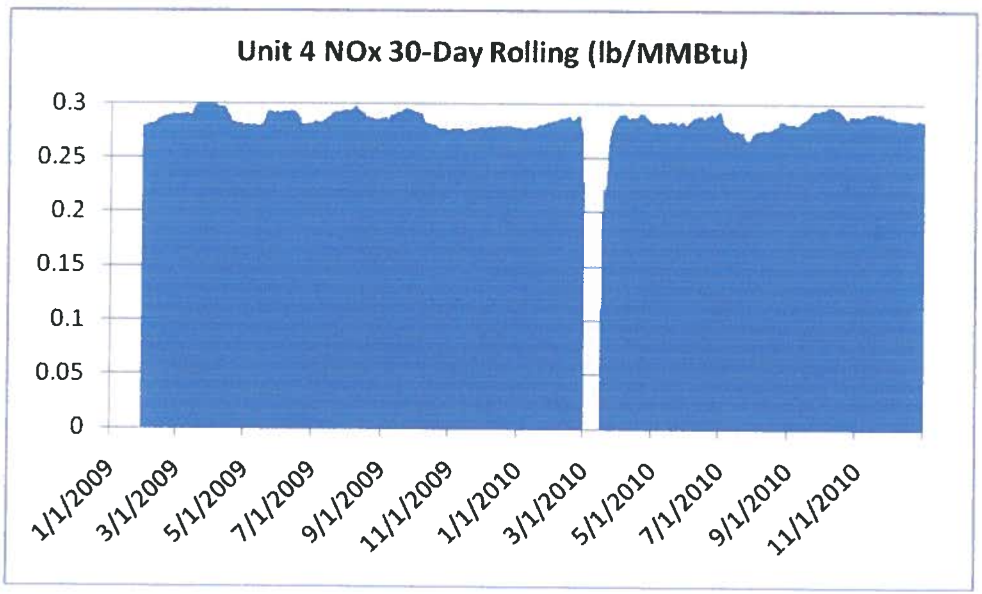
Max:Avg	1.047	1.111	1.100	1.077

In addition, the figures below show the 30-day rolling average data for each unit.









Based on the above, it is clear that: (a) for each unit, the average of the 30-day rolling average NOx did not exceed 0.29 lb/MMBtu; and (b) while there is expected variability in the 30-day rolling average values, this variability is not excessive. For example, the ratio of the maximum (of the 30-day rolling average values) to the average, is below 12% is all units. It ranges from a low of 4.7% for Unit 1 to a high of 11.1% for Unit 2. For purposes of this discussion, I will assume that the baseline NOx emissions for any of the four units is 0.29 lb/MMBtu.[7] Based on the fact that NOx emission rates from all 4 units are so similar, and that the 30-day average NOx values are only slightly below 0.30 lb/MMBtu for each unit, it appears that all 4 units are being operated in a manner that will ensure only minimum compliance with the Consent Decree (rather than achieve the lowest NOx rate possible). It is my opinion, as I will discuss next, that the boiler-out NOx emissions at SJGS could be somewhat lower. That said, I do not rely on lower boiler-out NOx emissions in my SCR discussion below. My analysis below assumes that boiler-out NOx rates are those shown in Table A above. But, to the extent the boiler out emissions can be lowered, it will simply provide additional compliance margin.

Finally, I note that based on EPA's 2010 CAMD data (i.e., even after full implementation of the consent decree above), the SJGS was the 18th highest NOx emitting coal-fired power plant in the US, out of 496 operating plants.

[7] The current controls at the SJGS include low-NOx burners (LNB), over-fire air (OFA) and neural networks (NN). See Table ES-1 of SJGS's June 6, 2007 BART Analysis submitted by Black and Veatch. All of these technologies are included inside the boiler. Hence, I will refer to NOx emissions coming out of the boiler as "boiler-out" NOx emissions.

C. Boiler Out NOx Emissions

There is considerable discussion in the record as to what the coal classification should be for the San Juan coal that is presently burned at the plant. San Juan coal is not easily classifiable because it exhibits characteristics of both bituminous and sub-bituminous coals. However, for purposes of a BART feasibility analysis, classifying SJGS's coal supply is less important than analyzing the specific coal properties that influence NOx generation in the boilers. Furthermore, it is important to note that the plant is likely to continue to operate after coal from the present mine is economically exhausted. It is not clear which type coal SJGS will burn after that occurs.[8]

The table below, taken from the 2007 Black and Veatch BART analysis for the SJGS, shows the coal properties as well as other design information for the plant's 4 units.[9]

Public Service Company of New Mexico (PNM) - San Juan Generating Station (SJGS)
Best Available Retrofit Technology (BART) Engineering Analysis
Design Basis Rev. 3

	SJGS Unit 1	Reference	SJGS Unit 2	Reference	SJGS Unit 3	Reference	SJGS Unit 4	Reference
Ultimate Coal analysis, wet basis								
Carbon, %	54.52	Ref 1	54.52	Ref 1	54.52	Ref 1	54.52	Ref 1
Hydrogen, %	4.24	Ref 1	4.24	Ref 1	4.24	Ref 1	4.24	Ref 1
Sulfur, %	0.77	Ref 1	0.77	Ref 1	0.77	Ref 1	0.77	Ref 1
Nitrogen, %	1.08	Ref 1	1.08	Ref 1	1.08	Ref 1	1.08	Ref 1
Oxygen, %	9.38	Ref 1	9.38	Ref 1	9.38	Ref 1	9.38	Ref 1
Chlorine, %	NA	Ref 1	NA	Ref 1	NA	Ref 1	NA	Ref 1
Ash, %	21.29	Ref 1	21.29	Ref 1	21.29	Ref 1	21.29	Ref 1
Moisture, %	8.72	Ref 1	8.72	Ref 1	8.72	Ref 1	8.72	Ref 1
Total, %	100.00	Ref 1	100.00	Ref 1	100.00	Ref 1	100.00	Ref 1
Higher Heating Value, Btu/lb	9,692	Ref 1	9,692	Ref 1	9,692	Ref 1	9,692	Ref 1
Unit Characteristics								
Unit Rating, Gross MW	360	Ref 2	350	Ref 2	544	Ref 2	544	Ref 2
Boiler Type	Wall-Fired	Ref 2	Wall-Fired	Ref 2	Opposed Wall-Fired	Ref 2	Opposed Wall-Fired	Ref 2
Boiler Heat Input, MBtu/h (HHV)	3,707	Ref 3	3,688	Ref 3	5,758	Ref 3	5,649	Ref 3
Coal Flow Rate, lb/h	382,480	Calculated	380,520	Calculated	594,098	Calculated	582,852	Calculated
Capacity Factor, %	85	Note 5	85	Note 5	85	Note 5	85	Note 5
Fly Ash Portion of Total Ash, %	80	Ref 4	80	Ref 4	80	Ref 4	80	Ref 4
Air Heater Leakage, %	15	Note 5	15	Note 5	15	Note 5	15	Note 5
Excess Air, %	20	Ref 5	20	Ref 5	20	Ref 5	20	Ref 5

In 2006, Sargent and Lundy created a Design Criteria document[10] in connection with the Consent Decree referenced earlier. In it, they provide a coal analysis, with similar but slightly different values. For example, in the Sargent and Lundy document, moisture content was noted as 10.2%, volatile matter at 34.3%, ash at 18.9%, and sulfur at 0.73%.

Although NOx emissions are influenced by the design of the boiler, burners and OFA as well as the manner in which the boiler is operated (for example, how many mills are in operation, the

[8] For example, in a report entitled "San Juan Generating Station Mercury Control Optimization Results" dated July 22, 2009, prepared by RMB Consulting for the San Juan plant, it is noted that "[A]t this time, PNM cannot define a future coal supply." See Appendix G of this report.
[9] Black and Veatch, PNM SJGS BART Analysis, June 6, 2007, Page A-2. EPA-R06-OAR-2010-0046-0013.8.pdf
[10] Sargent and Lundy, Design Criteria, June 15, 2006. p.7.

size distribution of the coal introduced, the degree of mixing of the coal and air, the variation of these with time, and other variables), which all determine the temperature profile within the boiler, NOx emissions are also influenced by certain coal properties. Among these properties are the moisture content, the volatile matter content, the oxygen content, and the nitrogen content. Taking the last first, the nitrogen content of San Juan coal (i.e., around 1%) is not much different from that of numerous other coals, both bituminous and sub-bituminous – for example, Table 4-3 of the 2007 BART analysis (by PNM consultant Black and Veatch)[11] indicates that the SJGS New Mexico "Subbituminous" coal nitrogen content is 1.08% while the comparison typical PRB coal nitrogen is 0.63%. The typical nitrogen content of low sulfur bituminous coal is 1.63%. Oxygen contents of the various coals as shown in the same Table 4-3 are also within a similar range. The moisture content of San Juan coal, at around 8-9% based on the table above (and greater than 10% per the Sargent and Lundy study), is lower than that of PRB coals (typically around 25-30%) but comparable to that of bituminous coals (again, Table 4-3 discussed earlier indicates a moisture content of 9.4% for the low-sulfur bituminous). In this regard, I note that it is more useful to compare as-fired moisture content as opposed to as-received (or some other similar basis) moisture content since NOx depends on the moisture content of the coal that is actually introduced into the boiler. Before being introduced to the boiler, the coal is pulverized, which results in a significant loss of moisture as compared to the moisture content of the same coal at the mine, in the rail car, or even at the pile. And, finally, the volatile matter of San Juan coal, while around 34%, is lower than that of PRB but higher than typical bituminous coals.

While it is well known that boiler-out NOx from the combustion of PRB coals can be quite low and in the range of 0.15 lb/MMBtu or even lower, it is more useful to compare boiler-out NOx from Units 1-4 to similar units firing similar (though not exactly the same) coals. One example is the two units at the Craig Station operated by TriState in Colorado. Units 1 and 2 are both Babcock and Wilcox opposed wall-fired dry bottom units, with capacity ratings of around 428 MW. Thus, in terms of size, they are between SJGS Units 1/2 and Units 3/4. Without the benefit of any regulatory constraint like the SJGS Consent Decree, these units had NOx levels of 0.278 lb/MMBtu (Unit 1) and 0.271 lb/MMBtu (Unit 2) in the 2006-2008 time period. In its various submittals to the Colorado Department of Public Health and the Environment (CDPHE)

[11] Black and Veatch, PNM SJGS BART Analysis, June 6, 2007, Page 4-5. EPA-R06-OAR-2010-0046-0013.8.pdf

during the BART development process, Tri-State noted that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal and that some amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. As the CDPHE noted, "....Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NOx formation." The characteristics of this combination of coal burned at the Craig units are thus similar to the characteristics of San Juan coal. These Craig units were emitting NOx at around 0.27-0.28 lb/MMBtu, which is lower than the 0.29 lb/MMBtu for Units 1-4.

Even lower NOx may be achievable out of the boiler. In a paper discussing their TFS-2000 firing system, Alstom notes that "....Best of class emissions range from 0.18 lb/MMBtu for bituminous coals to less than 0.10 lb/MMBtu for subbituminous coals, with typical levels at 0.24 lb/MMBtu and 0.13 lb/MMBtu, respectively."[12]

The point of the discussion above is to note simply that while the boiler out NOx emissions for Units 1-4 is currently around 0.29 lb/MMBtu, there may be room for some additional improvement in that regard. If so, it will be even easier (i.e., will provide additional margin) for compliance with the SCR-based NOx limit to be discussed next.

It should also be kept in mind that these units are not subject to stringent NOx permit limits and are therefore have little incentive to carefully maintaining low NOx performance. In other words, lower NOx emissions from the SJGS boilers are likely possible, with better and more careful in-boiler controls and their operation. Examples of additional improvements that could be considered include: (i) completing a detailed computational fluid dynamic (CFD) model of each boiler type (either 1 or 2 and either 3 or 4) in order to establish thermal and fluid properties affecting NOx generation at different loads to establish a thorough understanding of boiler parameters and constraints that affect NOx formation; (ii) establishing the NOx sensitivity to pulverizer mill operation and use – since this can affect air/fuel ratios and their distribution; (iii)

[12] Galen Richards, et al., Development of an Enhanced Combustion Low NOx Pulverized Coal Burner, Alstom Paper.

establishing proper set points in order to optimize NOx levels as well as those for CO and Loss on Ignition (LOI) etc.; (iv) establishing proper protocol to determine when the boiler is run under automatic control versus manual; (v) enhancing the neural network and adaptive logic-driven control system; and (vi) considering additional hardware changes such as modified low-NOx burners.

D. SCR Efficiency

As I noted above, I agree with EPA's contention that SCR technology will provide the best approach for further NOx reduction, beyond what is emitted from the boilers, at each of the SJGS units.

I also note that EPA's proposal of a 0.05 lb/MMBtu limit as compared to the current baseline of no more than 0.29 lb/MMBtu, both on a 30-day rolling average basis, means that the expected SCR efficiency is around 83%. Of course, if, as noted above, the SJGS Units could reduce their boiler-out NOx emissions to lower values, the expected SCR efficiency would be even lower in order to meet the 0.05 lb/MMBtu. For example, if the boiler-out NOx emissions were 0.28 lb/MMBtu, the SCR efficiency would be 82%; and if the boiler-out NOx emissions were 0.24 lb/MMbtu, the SCR efficiency would be 79%.

These SCR efficiencies are much too low, given current SCR capabilities. Of course, the SJGS units will not actually have to meet the BART requirement for at least another 3 years, under EPA's proposal.[13] In three years, SCR performance is likely to be even better (i.e., designed and operated to achieve higher efficiencies) than what I discuss below.

First, I note that EPA's selection of the 0.05 lb/MMBtu (as opposed to any other level, for example) is not explained or supported in its proposal. This choice does not reflect actual SCR performance being achieved today by many of the over 230+ SCRs that are operating on coal-fired units in the US. The technical report[14] on cost-effectiveness that accompanies the EPA proposal, notes that "...the 0.05 lb/MMBtu case, was **requested by** (emphasis added) EPA and assumes the SCR is designed to meet an outlet NOx emission limit of 0.05 lb/MMBtu..."[15] That report also notes that "[T]he catalyst was sized to meet 0.05 lb/MMBtu, so no change in catalyst volume is required..."[16] It also notes that "[T]he EPA requested that I estimate the cost of SCR,

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[13] 76 FR 492.
[14] Fox, P., Revised BART Cost Effectiveness Analysis for Selective Catalytic Reduction at the Public Service Company of New Mexico San Juan Generating Station, November 2010.
[15] Ibid., p. 23.
[16] Ibid., p. 23.

assuming an outlet NOx of 0.05 lb/MMBtu."[17] Based on these statements, it is clear that the choice of 0.05 lb/MMBtu was an assumption and was not based on an independent analysis of SCR capability or performance.

As is discussed in further detail below, while there is some correspondence in the record with PNM (relating to costs) and with certain SCR catalyst vendors, there does not appear to be any discussion with SCR catalyst vendors regarding what levels of NOx reduction efficiency can be achieved for Units 1-4. In fact, when EPA asked PNM about the potential for higher NOx removal efficiency using SCR, the response by its consultant Black and Veatch, was as follows:[18]

> 2. The emission reductions assume 77% NOx control. Please identify the basis and explain why a higher removal efficiency cannot be achieved.
>
> [PNM Response] The estimated emissions reductions were based on the expected capabilities of a retrofit SCR, which are somewhat lower than the emission reductions that a new SCR can achieve when included in the design for a new unit. The NOx emission value was established based on outlet NOx emissions, not removal efficiency, because outlet emissions are a more accurate representation of the true capability of SCR. To determine outlet emissions, we took into account the fact that San Juan Station would likely be given a new 30-day rolling average NOx limit that the plant will have to meet on a continuous basis.

The reference to 77% above is in relation to PNM's proposed NOx level using SCR of 0.07 lb/MMBtu. As is apparent from the above exchange, Black and Veatch simply dodged the question and the record shows no follow-up by EPA on this issue.

Second, to the extent EPA's judgment of SCR capabilities may be influenced by the type of coal that is burned by Units 1-4 (i.e., San Juan coal) and the lack of direct experience with SCRs burning this specific coal, EPA should note the following:

(i) while coal type is important, this is mainly because it determines the gas composition that will exit the boiler and therefore be sent to the SCR. Clearly, the SCR catalyst "sees" only what it receives – i.e., the exhaust gases from the boiler. In this case, given that the SCR would be located after the de-energized ESPs that are present at these units, and before the air preheater, a

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[17] Ibid., p. 28.
[18] See EPA-R06-OAR-2010-0846-0017.27.pdf, in the docket.

significant amount of fly-ash (assumed to be 50%)[19] is expected to be removed in the de-energized ESPs. Reduced fly-ash will make it that much easier for maintaining the first layer of SCR catalyst;

(ii) the sulfur content of San Juan coal, which is around 0.73-0.77%, is low. While it is marginally higher than the sulfur content of PRB coals, it is far lower than the sulfur content of eastern bituminous coals, which can be as high as 3%. Yet, there are numerous SCRs operating at 90% NOx removal efficiency at units with eastern bituminous coals. I will provide examples later. One of the concerns with sulfur is the extent to which the exhaust gases from the boiler contain sulfur trioxide or sulfuric acid mist (which can interact with the ammonia that is used for NOx reduction in the SCR). Together these compounds can form various ammonia salts that can plug or blind SCR catalysts. That is not a major concern here, however due to the low sulfur content of San Juan coal. Lower sulfur coal means less sulfur trioxide. Even assuming that around 1% or so of the sulfur dioxide that is created in the boiler is converted to sulfur trioxide that goes into the SCR, this is not a significant amount. In fact, the record supports my opinion that sulfur trioxide levels in the SCR inlet are likely to be low. For example, it appears that a fair amount of sulfur trioxide partitions from the gas to the particulate ash phase – and, in doing so, becomes unavailable for reaction with ammonia. As support for this phenomenon, the ash analysis for San Juan coal shows that it contains around 4.05% SO3.[20] The record also contains the results of sulfuric acid mist (which is the combination of SO3 and water vapor) testing at Units 1 and 3. Since the coal is the same, the results should be similar at the other units. While the three runs at Unit 1 showed significant variability, even the run with the greatest sulfuric acid (Run 1), had only 2 ppmvd of sulfuric acid mist. The other two runs at Unit 1 had levels of 0.3 and 0.1 ppmvd. Incidentally, using the actual heat input during the test runs (from EPA's CAMD database), the sulfuric acid mist emissions from Unit 1 (to the SCR) correspond to 0.0004-0.007 lb/MMBtu. Results for Unit 3 were 0-0.1 pppmvd.[21] None of these results demonstrate problematic levels of sulfuric acid mist. Thus, the low-sulfur coal at Units 1-4 removes a major impediment to SCR use and removes concerns for negative impacts to

[19] This is PNM's assumption. Compare "Economizer Outlet Conditions" and "De-Energized Hot-Side ESP Outlet Conditions" in Black and Veatch, PNM SJGS BART Analysis, June 6, 2007, Pages A-2 and A-3. EPA-R06-OAR-2010-0046-0013.8.pdf

[20] See Attachment 2, PNM Coal and Ash Analysis, B&V E-22, 10/21/10, p.11.

[21] EPA-R06-OAR-2010-0846-0017.17.pdf, in the docket at p.10 (.pdf).

downstream equipment such as air heaters – and this is confirmed by my discussions with SCR catalyst vendors;

(iii) The NOx levels in the boiler out gases are in the range of 160-200 ppm. This can be calculated by using the 0.29 lb/MMBtu and by making suitable assumptions regarding the coal composition or F-factor. It is also directly verifiable using actual test data. For example, the CEMS RATA tests for Unit 2 shows NOx concentrations of 160-170 ppmvd[22], and 170-180 ppmvd for Unit 3.[23] A RATA for 2008 for Unit 4 shows NOx concentrations of 178-186 ppmvd.[24] As discussed below, none of the major SCR catalyst vendors have any concerns meeting NOx reduction goals of 90% or greater at these NOx inlet concentrations to the SCR;

(iv) SCR catalysts are susceptible to several known poisons such as sodium, potassium, arsenic, etc. Yet, the record's analysis of San Juan coal[25] plainly demonstrates that these elements and their associated compounds exist at low or very low levels. For example, San Juan coal ash contains a sodium oxide concentration of only 1.48%, and contains less than a 1% concentration of magnesium and potassium oxides. Finally, the coal's arsenic concentration is 3 ppm. These are low levels and should not affect SCR catalysts, based on vendor discussions.

(v) At this time there are over 230 SCRs operating at US coal units (and many more worldwide) supplied by every variety of coal. In fact, SCRs are now operational even on lignite units,[26] a type of coal that is even more challenging than PRB and other western coals.

Thus, the type of coal is only an indirect issue. What is more important is the characteristics of the gas stream that enters the SCR. EPA does not provide any discussion, similar to the above, to explain why its proposed NOx limit for BART is only 0.05 lb/MMBtu and not lower.

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[22] Air Pollution Testing, RATA Test Report – SJGS Units 2 and 3, 2009.
[23] Ibid.
[24] Air Pollution Testing, RATA Test Report – SJGS Unit 4, 2008.
[25] [25] See Attachment 2, PNM Coal and Ash Analysis, B&V E-22, 10/21/10, p.11.
[26] Luminant's Oak Grove plant is 100% lignite based and has installed SCR. See http://www.powermag.com/instrumentation_and_controls/Luminants-Oak-Grove-Power-Plant-Earns-POWER-s-Highest-Honor_2877_p4.html

Third, it is widely recognized that today, all major SCR catalyst vendors[27] can easily guarantee at least 90% efficiency for SCR with the above-described (and significantly lower) inlet NOx levels, especially for units burning low-sulfur coals, such as these units.[28] In fact, it is likely, based on the fact that SCR designs today are achieving even greater than 90% reduction, that the 90% level is too conservative. The EPA proposal does not reference any recent studies relating to SCR efficiency or capability and does not appear to be based on any discussions with catalyst manufacturers.[29]

In the past few months, and just prior to providing these comments, I have confirmed, in discussions with at least three of the four major catalyst vendors referenced above (I could not contact the fourth), that they would be able to provide a 90% reduction (or greater, as discussed below) for Units 1-4, on a 30-day averaging basis.[30] I discussed the expected inlet NOx levels as noted above, the sulfur level in the coal (and resulting SO2, SO3, and sulfuric acid mist levels), the high ash content of the coal, and the presence of the alkaline oxides and arsenic. I also discussed the expected temperatures at the exit of the de-energized ESPs, based on Black and Veatch's design basis.[31] These temperatures are 695 F for Unit 1, 698 F for Unit 2, 640 F for Unit 3 and 673 F for Unit 4. Catalyst vendors confirmed that they could guarantee a 90% NOx removal efficiency. In fact, they noted that 90% removal was the current industry "standard" for SCR technology. Specifically, they also noted that with the expected (and confirmed) low levels of SO3, it may be feasible to install standard (roughly 1% SO2-SO3 conversion as opposed to the lower 0.5% conversion SO2-SO3) catalysts, without impacting the functionality of the downstream air pre-heaters. This will result in lower catalyst cost. It may even be feasible to install a 2x1 SCR design instead of a 3x1 SCR design,[32] further saving costs. They also noted

[27] These include Haldor Topsoe, Hitachi, Cormetech, Johnson-Matthey/Argillon, etc.

[28] Regardless of the confusion regarding classification of the coals that are burned at these units, it is clear that they are low-sulfur coals. Table 3 in the CDPHE BART determination notes that the sulfur content ranges from 0.36% to 0.49%.

[29] I note that the technical support document underlying the EPA's Proposed Rule does discuss at the end that SCR efficiencies should be 90% or better and that the expected NOx level of less than 0.05 lb/MMBtu are being achieved today.

[30] Personal communication, R. Sahu with representatives of Hitachi, Haldor Topsoe, and Johnson-Matthey/Argillon (November 2010, December 2010, March 2011)

[31] Black and Veatch, PNM SJGS BART Analysis, June 6, 2007, Page A-3. EPA-R06-OAR-2010-0046-0013.8.pdf

[32] A 3x1 SCR design refers to an arrangement in which there are 4 banks of SCR catalyst, with 3 filled and one available as a spare. In a 2x1 design, there would be 3 banks, with 2 filled and 1 spare. Of course one could also consider a configuration in which there are 4 banks available and only 2 are initially filled.

that as long as NOx inlet was greater than 100 ppm, 90% reduction should be no problem. Here, as I have discussed NOx levels are greater than 160 ppmvd, (and well over 100 ppm under actual conditions). These vendors also noted that the temperature at the expected catalyst location (i.e., between approximately 640-698F), is almost ideal from a catalyst activity standpoint. One vendor characterized the 650-725F range as the "sweet spot" in this regard.

Based on the above, it is my expert opinion that a 90% NOx reduction using SCR is undoubtably feasible at SJGS Units 1-4. In fact, it is likely, again based on the vendor discussions above, that even higher removal levels may be possible in the future.

Fourth, I note that the discussion above with the catalyst vendors is not surprising. It is well-documented that SCRs can achieve 90% NOx reduction and have been able to achieve this removal efficiency for years. I provide the following as general context, mainly reinforcing the point that 90% SCR NOx reduction is the norm and not an exception. Later, I will discuss specific examples.

Foster Wheeler, a vendor, notes that[33] AEP's Muskingum River Unit 5 in Ohio (a 600 MW unit) started using an SCR in 2005 with a NOx reduction of 90%. Also, the Indianapolis P&L Petersburg Units 2 and 3 (460-560 MW) have been achieving 90% removal from SCR since 2004.

In an analysis of data dating back to 2005, several studies conclude that SCRs routinely achieve NO_x removal efficiencies greater than 90%.[34] Detailed analyses of EPA's Acid Rain database indicate that "90% removal efficiency was currently [i.e., in 2005] being achieved by a significant portion of the coal-fired SCR fleet . . ..."[35] This was two years prior to the time Black and Veatch prepared its 2007 BART submittal for SJGS. More than 30 units have achieved

[33] Foster Wheeler SCR Brochure, 2008.

[34] Clayton A. Erickson et al., *Selective Catalytic Reduction System Performance and Reliability Review, The 2006 MEGA Symposium Paper #121*, pages. 1, 15; Clayton A. Erickson et al., *Selective Catalytic Reduction System Performance and Reliability Review Slides*, page 30; Competitive Power College, PowerGen 2005, Selective Catalytic Reduction – From Planning to Operation, 77.

[35] Clayton A. Erickson et al., *Selective Catalytic Reduction System Performance and Reliability Review, The 2006 MEGA Symposium Paper #121*, at 15.

greater that 90% NO_x reduction based on 2005 data.[36] 90% NO_x removal was achieved on 10,000 MW of coal-fired generation in 2004.[37] SCRs for many coal-fired units have been guaranteed to achieve greater than 90% NO_x reduction and are achieving greater than 90% reduction.[38] Another source (McIlvaine reports) indicate that three of Haldor Topsoe's SCR installations averaged over 95% NO_x reduction during the 2005 ozone season.[39]

Cormetech, a SCR catalyst vendor noted the following in a 2007 paper: "It is common for units to be designed for NOx removal efficiencies of 90%, and operate at efficiencies that are greater than the design value. As catalyst performance guarantees are defined to be those associated with the end of a specified lifetime, SCR catalyst that is early in its functional life has considerably higher capability. As an example, catalyst that is designed to achieve 90% NOx removal and 2 ppm ammonia slip after a lifetime of 24,000 operating hours will operate with virtually no ammonia slip at the beginning of its life."[40]

Similarly, back in 2003, Sargent and Lundy, an engineering firm that designs SCRs stated that "[A]ll Sargent & Lundy-designed SCR reactors at coal-fired units, which have been placed into service, have achieved their guaranteed NOx reduction efficiencies within the specified ammonia slip limits. The minimum design NOx reduction efficiency was 85% and the maximum reduction efficiency was in excess of 90%. Design ammonia slip levels ranged between 2 ppm and 3 ppm at the end of catalyst life. Although no SCR installations have yet operated for the guaranteed catalyst life duration, it is anticipated that the NOx reduction and ammonia slip performance guarantees will continue to be met over that period. Operational installations include pulverized coal units burning PRB coal, Illinois low- to high-sulfur coal, and eastern low- to high-sulfur

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[36] *Id.* at 1.

[37] Competitive Power College, PowerGen 2005. Selective Catalytic Reduction – From Planning to Operation, 77.

[38] Based on a comparison of ozone season (monthly average for June) and non-ozone season (monthly average for January) 2006 data from EPA's acid rain data base, these include the following: Chesapeake Energy Center Unit 3 (94.51%); John E. Amos Unit 1 (94.27%); John E. Amos Unit 2 (94.06%); Elmer Smith Unit 1 (93.6%); Mount Storm Unit 2 (93.53%); Dallman Unit 2 (93.39%); Dallman Unit 1 (93.24%); New Madrid Unit 1 (93.24%) and New Madrid Unit 2 (93.24).

[39] McIlvaine Utility e-Alert, No. 798. November 3, 2006. Mr. Nate White of Haldor Topsoe provided the following information: "Topsoe has over 100,000 hours of operating experience on PRB coal. In fact, three Topsoe supplied SCRs achieved the highest NO_x efficiency for all U.S. coal-fired high dust SCRs, averaging over 95% NO_x reduction over the 2005 Ozone season."

[40] Rutherford, S., Coal-Fired SCR Applications in the US – Challenges and Strategies for Successful Operation and Emission Compliance, Cormetech Inc., VGB Workshop "Flue Gas Cleaning 2007," Vienna, Austria, May 22 – 23, 2007

coal; one cyclone unit burning PRB coal; and two cyclone units burning Illinois low-sulfur coal. SCR reactor designs have included 2+1 and 3+1 catalyst level installation sequences and have used plate, honeycomb, and corrugated type catalysts. Design of SCR reactors for removal efficiencies greater than 90% at ammonia slip levels less than 2 ppm to 3 ppm has been demonstrated and should be considered as a feasible design criterion."[41]

In yet another example showing SCR performance to be as high as 93% reduction of NOx, the authors note that, "[T]he SCR system for the Unit 5 boiler at the Cliffside steam station operated at 93% NOx removal with the ammonia to NOx ratio variation within 5% for each reactor. While the SCR is not currently operated at this high NOx removal rate, the test results showed that the SCR is able to operate at high NOx removal without added risk to the catalyst or causing excessive ammonia slip."[42]

Additionally, achieving higher efficiencies with SCR is not limited to the US. In a paper discussing developments in China, Haldor Topsoe, a SCR catalyst vendor, stated that "[T]he Taishan Thermal Power Plant is a 5 × 600 MWe coal-fired power plant firing domestic coals. Unit 5 includes an SCR system, scheduled for start-up in 2006. Haldor Topsøe A/S is the supplier of the catalyst and critical components and has performed the system design including physical flow model tests. The DeNOx unit is guaranteed to have a NOx conversion at 94% with only 3 ppm ammonia slip."[43]

Finally, to show that far lower NOx levels than the 0.05 lb/MMBtu proposed by EPA can be expected, I provide the example from a Trimble County, KY coal unit. Riley Power supplied an SCR for this 547 MW unit and in a 2003 paper stated the following: "[T]he plant, built in 1990, was previously equipped with low NOx burners, a cold side ESP and a flue gas desulfurization system. The addition of the Riley Power Inc. Selective Catalytic Reduction system was designed

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[41] Kurtides, T., Lessons Learned From SCR Reactor Retrofit, COAL-GEN, August 6-8, 2003, Sargent and Lundy.
[42] Terence R. Ake, Clayton A. Erickson, and Linton K. Hutcheson, Increasing SCR NOx removal from 85% to 93% at the Duke Power Cliffside Steam Station, April 2006 ASME Power Division Special Section, ENERGY-TECH.com
[43] Jensen-Holm, H., et. al., Implementation of SCR DeNOx Technology on Coal-Fired Boilers in P.R. China, Haldor Topsoe, August 2006.

to reduce the outlet NOx concentration from 0.32 lb/MMBtu, by 90%, to 0.032 lb/MMBtu."[44] The table below is taken from the paper quoted above and shows that the unit was designed for a NOx level of 0.025 lb/MMBtu. The boiler-out NOx level of 0.32 lb/MMBtu is comparable to the current SJGS baseline NOx of 0.29 lb/MMBtu. The authors go on to note that

Outlet NOx Concentration National and State Regulations

Trimble County Power Plant	2004 SIP Call	2010 Kentucky Clear Skies for Coal Plants (6)	2010 Kentucky Clear Skies for Gas Plants (6)
0.025 lb/MBtu	0.15 lb/MBtu	0.12 lb/MBtu	0.04 lb/MBtu

"Based on Riley Power Inc. analysis and industry experience ....mixing systems with < 3% standard deviation can obtain ultra high NOx removal efficiencies of > 93% with the correct catalyst volume."

In yet another example, at the Seminole Generating Station retrofit, the authors from Hitachi (the SCR supplier) note that[45] "Units 1 and 2 at the Seminole Generating Station are each nominally rated at 650 MWe and burn eastern bituminous coal. In 2006, the contract for the retrofits of selective catalytic reduction (SCR) for both units was awarded to Hitachi Power Systems America, Ltd (HPSA). The SCR systems are designed for 90% NOx reduction and are equipped with Hitachi low SO2-oxidation, plate-type catalyst, and a unique ammonia injection grid (AIG)/static mixing system to promote thorough mixing of ammonia and NOx prior to entering the SCR catalyst."

[44] Erickson, C., et. al., Coal-Fired SCR Operating Experience with High Removal Efficiency and Low-Nox Firing Systems, 2003.
[45] Gretta, W.J., et. al., The SCR Retrofit Design For The Seminole Generating Station.

Table 1 - Design Criteria for Seminole Units 1 and 2 (MCR Conditions)

Design Parameter	Value
Gas Flow Rate	6.516.886 lb/hr
Temperature	750°F
Inlet NO_x	0.413 lb
Outlet NO_x	0.04 lb
SO_2 Conversion	<0.5%
Ammonia Slip	<2 ppmvd

Please note that these are bituminous coal fired units, and are therefore comparable to the San Juan units as far as their NOx emissions are concerned, as claimed by PNM. The table shown below is excerpted from this paper and shows that, as far back as 2006, the design basis for the SCR (outlet NOx value below) was 0.04 lb/MMBtu. As the paper notes, "[T]he required outlet NO_x for SGS Units 1 and 2 was set at 0.04 lb/MMBtu, which equates to a NOx reduction of 90%. This guaranteed NO_x reduction represents the end-of-life performance after catalyst deactivation has taken place." Please also note that the ammonia slip is less than 2%.

I should note that in many of the instances above, units are not meeting their design values. The underlying reason for that is simple — most of them have permit limits that are too high. Therefore, there is no regulatory driver that compels them to meet these low design values. It would be incorrect for EPA to conclude that because units today are not, in general, meeting their low design levels that it is a reflection of the state of SCR technology or boiler low-NOx technology. Rather, it is more a function of permit limits that are set without regard to what the technology can do.

Fifth, EPA's own comments support a more stringent NOx limit for BART. For example, on the Colorado BART NOx proposals by various utilities, EPA Region VIII noted the following for TriState's Craig station proposed BART of 0.07 lb/MMBtu (which is exactly what PNM initially proposed for SCR for Units 1-4):[46]

[46] EPA Region VII Letter dated October 26, 2010 to Mr. Paul Tourangeau, Director Air Pollution Division, CDPHE

"**EPA Comment** 9. The Division uses an emission rate of 0.07 lb/MMBtu in its analysis of the SCR control option for several sources. However, many EGUs that have installed SCR retrofits have demonstrated performance levels below 0.07 lb/MMBtu. A CAMD database search reveals that many boilers retrofitted with SCR are achieving an emission rate of 0.03 - 0.061b/MMBtu. Accordingly, the State needs to use an emission rate in the analyses that takes into consideration that which is currently being demonstrated at similar facilities."

"EPA Comment 42. This section states that new SCR installations should be able to achieve a lower NOx emission rate than retrofit installations, suggesting that no more than 0.07 lb/MMBtu can be expected for a retrofit. However, many EGUs that have installed SCR retrofits under Title IV or other eastern emission control programs have demonstrated performance levels below 0.07 lb/MMBtu. A CAMD database search reveals that for boilers similar to the Craig BART units (i.e., dry bottom wall fired units burning bituminous coal, or in this case, bituminous-like, with existing LNB/OFA controls), there are sixteen units that achieved a NOx emission rate of 0.03 - 0.06 lb/MMBtu in 2009. The determination of the appropriate emission limit for the Craig BART units needs to be made in consideration of what is already being achieved for similar units, such as those found in the CAMD database."

Even in this record, EPA has noted in the preamble to the proposed rule that "...NMED evaluated the visibility benefits of SCR at the SJGS based on an emission limit of 0.07 lbs/MMBtu, but noted the potential for greater control at rates as low as 0.03 lbs/MMBtu."[47] Yet, EPA has absolutely no discussion as to why it did not evaluate this lower value in its feasibility analysis.

Sixth, I have reviewed actual SCR performance from 2010. Table B below shows units that have achieved NOx levels of below 0.05 lb/MMBtu as reported to EPA's CAMD. I took the monthly (i.e.., reflecting approximately 30-day average values) NOx data for all SCR coal-fired units in the CAMD. I ranked them in order of increasing NOx emission rates in lb/MMBtu. The table shows all unit-months that are less than 0.05 lb/MMBtu. There are 266 unit-months of actual

[47] 76 FR 499.

data reflected in the table. Even more importantly, none of these units have emission limits that are low (i.e., 0.05 lb/MMBtu) so the performance reflects essentially no regulatory driving-force. The point of this table is to show that many units today, firing a broad range of coals, are achieving 30-day average NOx levels lower than 0.05 lb/MMBtu, in the absence of strict permit limits. EPA should give this data appropriate weight and consideration.

Table B – 2010 Monthly NOx Below 0.05 lb/MMBtu

ST	FACILITY	ORISPL	UNIT	Year	MONTH	OP_TIME (hrs/mo)	**NOx_Rate (lb/MMBtu)**	NOx_Mass (tons/mo)	Heat_Input (MMBtu/mo)
WI	Elm Road Generating Station	56068	2	2010	11	530.16	**0.024**	16.679	1615798.73
IL	Havana	891	9	2010	3	744	**0.0278**	40.689	2914953.8
MD	Morgantown	1573	2	2010	9	720	**0.0289**	50.095	3456521.1
WV	John E Amos	3935	1	2010	2	671.93	**0.0297**	59.014	3984535.22
OH	Conesville	2840	4	2010	5	166.67	**0.0299**	12.769	847425.319
IL	Havana	891	9	2010	1	744	**0.0301**	49.336	3269397.9
VA	Chesapeake Energy Center	3803	4	2010	1	744	**0.0306**	22.815	1504002.8
KY	Trimble County	6071	1	2010	12	744	**0.0307**	58.154	3792541.2
VA	Chesapeake Energy Center	3803	3	2010	2	672	**0.0311**	14.477	930516.1
VA	Chesapeake Energy Center	3803	3	2010	3	744	**0.0312**	14.739	944962.8
VA	Chesapeake Energy Center	3803	3	2010	11	51.98	**0.0312**	0.114	6489.196
MD	Morgantown	1573	2	2010	7	744	**0.0317**	66.846	4209333.9
IL	Havana	891	9	2010	7	695.38	**0.0318**	50.117	3256521.56
VA	Chesapeake Energy Center	3803	4	2010	5	729.67	**0.032**	21.308	1412080.73
NC	Marshall	2727	3	2010	7	744	**0.0321**	70.49	4357627.5
VA	Chesapeake Energy Center	3803	3	2010	1	694.88	**0.0322**	14.426	930631.474
MD	Morgantown	1573	2	2010	8	608.08	**0.0324**	50.447	3246018.51
NC	Belews Creek	8042	2	2010	8	743.78	**0.0328**	106.914	7274577.64
OH	Cardinal	2828	1	2010	9	720	**0.0328**	61.666	3698422.5
IL	Havana	891	9	2010	6	720	**0.0332**	54.886	3312980.3
OH	Cardinal	2828	1	2010	10	744	**0.0335**	66.144	3927415
OH	Cardinal	2828	3	2010	3	744	**0.0335**	66.588	4013461.6
VA	Chesapeake Energy Center	3803	3	2010	5	707.24	**0.0338**	13.811	857568.954
VA	Chesapeake Energy Center	3803	4	2010	3	735.34	**0.034**	22.202	1417572.43
TX	Sandow	6648	4	2010	10	744	**0.0344**	68.777	4118368.7
VA	Chesapeake Energy Center	3803	3	2010	4	579.82	**0.0344**	11.475	703892.443
IL	Havana	891	9	2010	9	719.98	**0.0345**	48.899	2884202.32
MD	Morgantown	1573	1	2010	10	724.41	**0.0346**	55.183	3284202.36
IL	Havana	891	9	2010	4	614.14	**0.0348**	31.836	2241132.88
NC	Marshall	2727	3	2010	1	744	**0.0349**	76.197	4377178.9
MD	Morgantown	1573	1	2010	11	720	**0.035**	63.143	3505869.5
IL	Havana	891	9	2010	2	506.87	**0.0351**	29.268	2030833.67

IN	Merom	6213	1SG1	2010	5	59.26	**0.0353**	0.256	10945.529
MD	Morgantown	1573	2	2010	10	656.72	**0.0354**	44.203	2798375.14
AL	Charles R Lowman	56	2	2010	10	16.57	**0.0356**	0.127	4545.378
MD	Morgantown	1573	2	2010	11	683.75	**0.0357**	51.885	3070620.86
MD	Morgantown	1573	1	2010	8	744	**0.0359**	81.98	4409440.6
NC	Marshall	2727	3	2010	4	720	**0.036**	77.187	4303934.9
KY	Trimble County	6071	1	2010	9	719.5	**0.0363**	59.426	3364268.65
VA	Chesterfield Power Station	3797	5	2010	7	744	**0.0363**	40.662	2242742.8
WV	Mitchell (WV)	3948	1	2010	4	720	**0.0364**	82.475	4588058.7
IL	Havana	891	9	2010	5	734.74	**0.0365**	52.617	3245884.91
TX	J K Spruce	7097	**2	2010	4	168	**0.0366**	22.242	1217980.1
AL	Colbert	47	5	2010	3	744	**0.0368**	46.484	2526599.3
OH	Cardinal	2828	1	2010	11	457.55	**0.0369**	43.769	2392745.44
NC	Belews Creek	8042	2	2010	9	672.9	**0.0372**	92.219	5888759.1
OH	Cardinal	2828	1	2010	2	672	**0.0372**	69.109	3711452.6
FL	Crystal River	628	5	2010	8	744	**0.0373**	97.654	5196328.9
MD	Morgantown	1573	2	2010	6	720	**0.0373**	71.087	3812198.6
FL	Crystal River	628	5	2010	7	744	**0.0374**	99.571	5308677.9
TX	Sandow	6648	4	2010	9	565.49	**0.0378**	40.18	2967117.61
NC	Marshall	2727	3	2010	6	720	**0.0379**	74.508	4008559.5
NC	Marshall	2727	3	2010	8	701.42	**0.0381**	68.535	3855414.24
AL	Colbert	47	5	2010	4	23.25	**0.0382**	1.675	91813.125
OH	Cardinal	2828	3	2010	6	699.79	**0.0384**	69.792	3815195.3
MD	Chalk Point	1571	1	2010	11	720	**0.0385**	42.613	2234467
IL	Havana	891	9	2010	8	697.95	**0.0387**	56.012	3366185.87
NV	TS Power Plant	56224	1	2010	6	720	**0.0387**	22.771	1170043.6
TX	J K Spruce	7097	**2	2010	7	743.75	**0.0389**	120.168	6216084.48
WV	Mitchell (WV)	3948	2	2010	2	671.93	**0.0389**	92.47	4769579.89
NC	Belews Creek	8042	2	2010	12	744	**0.0393**	145.673	7432866.2
OH	Cardinal	2828	1	2010	3	456.32	**0.0393**	48.418	2455799.94
NC	Belews Creek	8042	1	2010	5	744	**0.0395**	141.262	7141199.7
OH	Cardinal	2828	3	2010	2	594.63	**0.0395**	57.122	3302153.94
FL	Crystal River	628	4	2010	11	710	**0.0397**	75.952	3899776.2
NC	Belews Creek	8042	1	2010	6	720	**0.0397**	137.828	6952599.7
TX	W A Parish	3470	WAP7	2010	3	744	**0.0398**	66.159	3320279.9
TX	W A Parish	3470	WAP8	2010	5	741.9	**0.0399**	72.929	3702455.71
TX	W A Parish	3470	WAP8	2010	12	744	**0.0399**	82.463	4180705.7
FL	Crystal River	628	5	2010	12	744	**0.04**	102.533	5110098.2
MD	Morgantown	1573	2	2010	12	744	**0.04**	84.407	4227134
TX	W A Parish	3470	WAP8	2010	7	744	**0.04**	82.127	4145357.2
VA	Chesapeake Energy Center	3803	4	2010	6	660.41	**0.04**	24.353	1312762.43
TX	W A Parish	3470	WAP8	2010	6	664.28	**0.0401**	74.072	3729279.96
TX	W A Parish	3470	WAP7	2010	2	672	**0.0402**	66.23	3298478.9
TX	W A Parish	3470	WAP8	2010	4	633.15	**0.0402**	56.499	2852750.88
IL	Coffeen	861	1	2010	10	693.32	**0.0403**	41.727	2104781
KY	Trimble County	6071	1	2010	7	715.3	**0.0403**	65.694	3430045.06
WV	Mitchell (WV)	3948	1	2010	1	744	**0.0403**	100.168	5004829.3
FL	Crystal River	628	5	2010	10	744	**0.0404**	89.5	4425716.3
TX	W A Parish	3470	WAP8	2010	1	744	**0.0404**	79.245	3896649.3
AL	Colbert	47	5	2010	2	672	**0.0405**	46.969	2338036.4
MD	Morgantown	1573	1	2010	5	744	**0.0405**	83.558	3944591.6
TX	W A Parish	3470	WAP8	2010	11	720	**0.0405**	66.756	3350600.7
FL	Crystal River	628	4	2010	8	682.75	**0.0406**	79.886	4158921.43

NV	TS Power Plant	56224	1	2010	5	207.71	**0.0406**	4.542	269940.994
PA	Keystone	3136	2	2010	8	744	**0.0406**	124.326	6126809.2
VA	Chesterfield Power Station	3797	5	2010	3	739.52	**0.0408**	41.206	2057286.29
OH	Cardinal	2828	3	2010	9	720	**0.0409**	82.072	3993959.7
FL	Crystal River	628	4	2010	7	717.75	**0.041**	91.409	4601588.35
TX	W A Parish	3470	WAP8	2010	2	626.97	**0.041**	68.555	3364689.62
KY	Trimble County	6071	1	2010	8	716.95	**0.0411**	68.658	3388074.1
NC	Marshall	2727	3	2010	12	737.47	**0.0411**	90.551	4368689.63
TX	W A Parish	3470	WAP8	2010	10	744	**0.0411**	66.182	3330564.9
OH	Cardinal	2828	1	2010	6	712.96	**0.0412**	72.453	3603737.46
TX	W A Parish	3470	WAP8	2010	8	688.31	**0.0413**	78.526	3833503.1
MI	Dan E Karn	1702	2	2010	7	744	**0.0414**	36.707	1770888.9
IL	Coffeen	861	2	2010	9	557.53	**0.0416**	64.645	3148760.38
MD	Morgantown	1573	2	2010	5	362.24	**0.0416**	26.481	1468908.07
NV	TS Power Plant	56224	1	2010	9	720	**0.0416**	24.541	1178235.9
WV	John E Amos	3935	1	2010	3	459.02	**0.0416**	39.125	2270584.3
NC	Belews Creek	8042	2	2010	1	744	**0.0417**	132.837	6426587.6
TX	J K Spruce	7097	**2	2010	8	744	**0.0417**	130.419	6267765
KY	Mill Creek	1364	4	2010	9	720	**0.0419**	69.704	3340344
TX	J K Spruce	7097	**2	2010	6	720	**0.0419**	128.915	6146264
IA	Walter Scott Jr. Energy Center	1082	4	2010	10	744	**0.042**	105.39	5007763.1
MN	Boswell Energy Center	1893	3	2010	7	743.65	**0.042**	53.775	2605471.73
TX	W A Parish	3470	WAP7	2010	4	720	**0.042**	65.767	3126543
TX	W A Parish	3470	WAP8	2010	9	614.86	**0.042**	62.346	3047688.65
FL	Crystal River	628	5	2010	9	629	**0.0422**	77.701	3928045.08
MI	Dan E Karn	1702	1	2010	11	720	**0.0423**	30.273	1432772.6
TX	W A Parish	3470	WAP7	2010	1	744	**0.0423**	72.495	3404268.7
NC	Marshall	2727	3	2010	5	744	**0.0426**	93.087	4346776.5
WV	John E Amos	3935	1	2010	5	743.95	**0.0426**	86.776	4136087.9
VA	Chesapeake Energy Center	3803	3	2010	6	720	**0.0427**	21.137	998340.4
PA	Keystone	3136	2	2010	9	720	**0.0428**	124.082	5791138.9
MD	Morgantown	1573	2	2010	3	121.87	**0.0429**	13.052	632321.844
OH	Cardinal	2828	2	2010	4	720	**0.0429**	84.246	3894254.7
IL	E D Edwards	856	3	2010	8	744	**0.043**	50.787	2360676.1
VA	Chesterfield Power Station	3797	5	2010	4	720	**0.043**	42.029	1965111.2
MI	Dan E Karn	1702	2	2010	5	744	**0.0431**	36.514	1676595.4
NV	TS Power Plant	56224	1	2010	12	744	**0.0431**	28.127	1305839.1
MD	Morgantown	1573	1	2010	7	615.8	**0.0432**	64.155	3326537.5
OH	Cardinal	2828	3	2010	7	674.43	**0.0432**	78.136	3653341.08
WI	Elm Road Generating Station	56068	1	2010	5	645.7	**0.0432**	47.068	2277466.65
IL	E D Edwards	856	3	2010	9	695.97	**0.0433**	39.916	1833420.95
MO	Sibley	2094	3	2010	2	670.75	**0.0433**	51.585	2411748
IL	Havana	891	9	2010	12	718.16	**0.0434**	66.55	3492184.2
NV	TS Power Plant	56224	1	2010	7	744	**0.0434**	28.294	1297475.8
WV	Mitchell (WV)	3948	2	2010	4	720	**0.0434**	108.81	5040189.4
KY	D B Wilson	6823	W1	2010	8	744	**0.0435**	69.932	3207456.6
MD	Morgantown	1573	1	2010	9	577.32	**0.0436**	64.769	2849832.64
MI	Dan E Karn	1702	1	2010	8	744	**0.0436**	38.25	1740043.3
NV	TS Power Plant	56224	1	2010	11	701.98	**0.0437**	26.199	1194532.74
PA	Keystone	3136	2	2010	5	744	**0.0438**	127.333	5824804.1
FL	Crystal River	628	5	2010	6	674.5	**0.0439**	93.977	4385915.25

KY	Trimble County	6071	1	2010	10	622.59	**0.0439**	61.242	2816680.53
KY	Trimble County	6071	1	2010	11	692.83	**0.0439**	68.838	3264164.97
OH	Conesville	2840	4	2010	9	192.73	**0.0439**	20.857	979544.042
TX	J K Spruce	7097	**2	2010	5	407.5	**0.0439**	63.048	3102037.65
KY	Ghent	1356	1	2010	10	744	**0.0441**	61.877	3055470.7
OH	Conesville	2840	4	2010	6	510.44	**0.0442**	56.564	2949485.44
WV	Mitchell (WV)	3948	2	2010	1	744	**0.0442**	116.672	5293732.8
NC	Belews Creek	8042	2	2010	11	720	**0.0443**	148.495	6734467.3
OH	Cardinal	2828	1	2010	5	495.92	**0.0443**	48.833	2362976.5
TX	W A Parish	3470	WAP7	2010	12	659.65	**0.0443**	62.689	2913254.52
MD	Morgantown	1573	2	2010	2	672	**0.0444**	75.96	3381429.9
PA	Keystone	3136	2	2010	10	744	**0.0444**	134.278	6036814.9
VA	Chesterfield Power Station	3797	5	2010	1	744	**0.0444**	47.882	2207678.9
WI	Elm Road Generating Station	56068	1	2010	11	685.7	**0.0444**	77.913	3505529.75
NV	TS Power Plant	56224	1	2010	10	743.15	**0.0447**	26.228	1173281.24
VA	Chesterfield Power Station	3797	6	2010	1	606.17	**0.0447**	82.792	3738538.09
WV	John E Amos	3935	3	2010	12	577.67	**0.0447**	169.958	7593177.49
OH	Cardinal	2828	1	2010	7	687.74	**0.0449**	73.175	3543200.3
PA	Keystone	3136	2	2010	6	715.73	**0.0449**	122.603	5667520.55
NV	TS Power Plant	56224	1	2010	8	744	**0.045**	28.536	1262264.8
AL	Colbert	47	5	2010	7	744	**0.0452**	61.183	2765093.8
PA	Keystone	3136	2	2010	4	720	**0.0452**	125.975	5691292.1
IA	Walter Scott Jr. Energy Center	1082	4	2010	9	720	**0.0453**	106.31	4694311.6
WV	Mountaineer (1301)	6264	1	2010	7	744	**0.0453**	192.296	8491985.4
IL	E D Edwards	856	3	2010	11	720	**0.0454**	48.53	2137133.1
KY	D B Wilson	6823	W1	2010	2	671.25	**0.0454**	75.687	3395228.5
MN	Boswell Energy Center	1893	3	2010	6	720	**0.0454**	57.792	2558729.1
MI	Dan E Karn	1702	2	2010	2	672	**0.0455**	32.468	1379244.8
NC	Belews Creek	8042	1	2010	10	744	**0.0455**	152.141	6664696.7
PA	Keystone	3136	2	2010	1	744	**0.0455**	127.776	5738525.8
IL	Coffeen	861	2	2010	8	744	**0.0457**	104.348	4547163.3
IL	E D Edwards	856	3	2010	12	744	**0.0457**	57.854	2532899.5
AL	Widows Creek	50	8	2010	6	720	**0.0458**	67.526	2971988.5
IL	Dallman	963	4	2010	10	592.67	**0.0458**	18.562	825529.033
IL	Coffeen	861	1	2010	8	744	**0.0459**	59.204	2586716.5
NC	Belews Creek	8042	1	2010	3	742.08	**0.046**	150.096	6931180.59
IL	E D Edwards	856	3	2010	1	744	**0.0461**	60.707	2638479.4
KY	D B Wilson	6823	W1	2010	3	744	**0.0461**	81.741	3592349.7
OH	Cardinal	2828	2	2010	1	744	**0.0461**	92.593	3995099.1
IL	Baldwin Energy Complex	889	2	2010	5	744	**0.0462**	96.799	4188560
IL	Baldwin Energy Complex	889	2	2010	6	720	**0.0462**	94.31	4085731.5
TN	Kingston	3407	8	2010	10	335.63	**0.0462**	13.279	579027.87
GA	Wansley (6052)	6052	1	2010	9	720	**0.0463**	102.914	4421515.2
KY	Ghent	1356	1	2010	6	720	**0.0463**	70.769	3338426.9
NC	Belews Creek	8042	2	2010	10	744	**0.0463**	153.205	6390701.7
WV	Mitchell (WV)	3948	2	2010	3	743.72	**0.0463**	111.573	4862800.78
TN	Cumberland	3399	1	2010	2	672	**0.0464**	156.683	6707601.4
WV	John E Amos	3935	3	2010	1	744	**0.0464**	194.992	8342431.2
VA	Chesapeake Energy Center	3803	4	2010	2	483.74	**0.0465**	19.612	899581.056

AL	Colbert	47	5	2010	8	744	**0.0466**	52.485	2303826.8
KY	D B Wilson	6823	W1	2010	1	721.75	**0.0466**	80.825	3583508.4
IN	Gibson	6113	1	2010	9	719.88	**0.0467**	85.115	3711695.32
IL	Baldwin Energy Complex	889	1	2010	7	744	**0.0468**	93.198	3979895.3
IL	Baldwin Energy Complex	889	2	2010	3	744	**0.0468**	96.802	4137585.2
IL	Coffeen	861	1	2010	12	672.8	**0.0468**	50.174	2182795.74
KY	Mill Creek	1364	4	2010	8	744	**0.0468**	84.53	3583427.2
WV	Mitchell (WV)	3948	1	2010	7	744	**0.0468**	112.427	4794099.1
OH	Conesville	2840	4	2010	8	703.65	**0.0469**	94.668	4358542.02
GA	Wansley (6052)	6052	1	2010	8	744	**0.047**	112.513	4760051.1
MA	Brayton Point	1619	1	2010	9	716.75	**0.047**	28.096	1512860.7
MD	Morgantown	1573	1	2010	2	672	**0.047**	84.006	3470618.9
WV	Mitchell (WV)	3948	1	2010	2	587.78	**0.047**	82.885	3909154.07
FL	Crystal River	628	5	2010	3	735.75	**0.0471**	103.49	4555312.75
OH	Cardinal	2828	2	2010	9	172.77	**0.0471**	20.543	867334.852
TX	W A Parish	3470	WAP8	2010	3	122.05	**0.0471**	6.475	265190.862
FL	Crystal River	628	5	2010	4	720	**0.0472**	98.592	4103023.8
KY	Ghent	1356	1	2010	11	719.15	**0.0472**	67.66	3044527.7
FL	Crystal River	628	4	2010	12	735.25	**0.0473**	88.204	4266703
FL	Deerhaven	663	B2	2010	11	720	**0.0473**	32.486	1342922.8
MD	Morgantown	1573	1	2010	12	739.94	**0.0473**	99.253	4205664.18
IL	Baldwin Energy Complex	889	1	2010	1	744	**0.0474**	92.716	3906758
WV	Mountaineer (1301)	6264	1	2010	4	720	**0.0474**	165.426	6997016.9
OH	Cardinal	2828	3	2010	10	375.94	**0.0475**	39.503	2016743.43
IL	E D Edwards	856	3	2010	10	647.46	**0.0476**	40.002	1761762.54
IL	Havana	891	9	2010	11	561.13	**0.0476**	48.264	2408570.6
MN	Boswell Energy Center	1893	3	2010	8	741	**0.0476**	61.485	2691021.46
NC	Belews Creek	8042	1	2010	1	744	**0.0476**	156.433	6860380.7
FL	Crystal River	628	4	2010	10	701.25	**0.0477**	65.698	3013678.35
IA	Walter Scott Jr. Energy Center	1082	4	2010	11	707.25	**0.0477**	101.924	4427111.75
IL	Dallman	963	4	2010	6	720	**0.0477**	26.712	1151525.9
FL	Crystal River	628	5	2010	11	547	**0.0478**	72.042	3179984.7
GA	Wansley (6052)	6052	1	2010	6	720	**0.0478**	116.486	4852306.4
IL	Baldwin Energy Complex	889	1	2010	3	744	**0.0478**	94.836	3971736.5
IL	Baldwin Energy Complex	889	2	2010	7	674.42	**0.0478**	88.111	3795232.95
IL	E D Edwards	856	3	2010	7	744	**0.0479**	55.845	2343103.2
KY	Mill Creek	1364	3	2010	3	743.98	**0.0479**	70.956	2963084.15
MN	Boswell Energy Center	1893	3	2010	12	717.6	**0.0479**	61.564	2683363.83
OH	Cardinal	2828	1	2010	1	565.53	**0.0479**	58.716	2907002.33
GA	Wansley (6052)	6052	1	2010	5	744	**0.048**	103.966	4316546
KY	Ghent	1356	1	2010	7	719.08	**0.048**	73.661	3316368.1
VA	Chesterfield Power Station	3797	6	2010	3	744	**0.048**	98.678	4100817.8
IL	Dallman	963	4	2010	9	488.09	**0.0481**	17.56	744135.427
VA	Chesapeake Energy Center	3803	3	2010	9	649.19	**0.0481**	17.943	827720.542
WV	Mountaineer (1301)	6264	1	2010	12	744	**0.0481**	209.779	8739147.3
IL	Baldwin Energy Complex	889	2	2010	12	744	**0.0482**	102.709	4265066.1
IL	Havana	891	9	2010	10	683.58	**0.0482**	54.07	2802926.74

OH	Cardinal	2828	1	2010	8	597.23	**0.0482**	64.415	3039835.08
OH	Muskingum River	2872	5	2010	7	744	**0.0482**	95.516	3921805.2
IA	Walter Scott Jr. Energy Center	1082	4	2010	4	385.25	**0.0483**	61.478	2464286.5
TX	J K Spruce	7097	**2	2010	9	63.25	**0.0483**	12.357	509677.725
GA	Wansley (6052)	6052	1	2010	7	744	**0.0484**	120.278	4944679.9
KY	D B Wilson	6823	W1	2010	5	744	**0.0484**	74.708	3062542.5
WV	John E Amos	3935	1	2010	4	443.6	**0.0485**	41.437	2317814.07
KY	Ghent	1356	1	2010	9	720	**0.0486**	72.113	3193524.8
MO	Iatan	6065	2	2010	12	744	**0.0486**	117.985	4886325.3
OH	Muskingum River	2872	5	2010	6	720	**0.0486**	80.921	3590126.5
VA	Chesterfield Power Station	3797	5	2010	6	716.7	**0.0487**	49.243	2102237.91
WV	John E Amos	3935	2	2010	4	720	**0.0487**	115.76	4756840
AL	Colbert	47	5	2010	5	499.65	**0.0488**	38.423	1750568.48
NC	Belews Creek	8042	1	2010	8	697.55	**0.0488**	143.775	6509737.07
WV	Mountaineer (1301)	6264	1	2010	3	741.22	**0.0488**	181.745	7584673.21
MI	Dan E Karn	1702	1	2010	5	654.46	**0.049**	36.766	1550797.36
KY	D B Wilson	6823	W1	2010	9	687	**0.0491**	70.738	2934416.2
IL	Dallman	963	4	2010	11	652.23	**0.0492**	20.224	814749.048
KY	Mill Creek	1364	4	2010	4	694.6	**0.0492**	74.861	3171917.37
TX	W A Parish	3470	WAP6	2010	11	720	**0.0492**	81.932	3356456
TX	W A Parish	3470	WAP5	2010	11	720	**0.0493**	81.037	3329737.5
AL	Widows Creek	50	8	2010	1	744	**0.0495**	79.658	3247371.8
WV	John E Amos	3935	1	2010	1	687.76	**0.0495**	95.568	3878230.08
GA	Wansley (6052)	6052	2	2010	7	744	**0.0496**	130.108	5208793
WV	Mountaineer (1301)	6264	1	2010	8	744	**0.0496**	214.202	8621599.8
KY	Mill Creek	1364	4	2010	10	744	**0.0497**	83.075	3301408.1
TN	Cumberland	3399	1	2010	4	720	**0.0497**	181.967	7281828.4
GA	Wansley (6052)	6052	2	2010	5	744	**0.0498**	115.731	4616113.6
MA	Brayton Point	1619	1	2010	7	727.5	**0.0498**	29.622	1606081.35
OH	Cardinal	2828	2	2010	8	744	**0.0498**	101.311	3962526.9
OH	Cardinal	2828	3	2010	5	571.23	**0.0498**	59.931	3065435.25
WI	Elm Road Generating Station	56068	1	2010	12	734.15	**0.0498**	86.738	3434939.84
NC	Marshall	2727	3	2010	2	638.55	**0.0499**	85.9	3696221.03
TX	W A Parish	3470	WAP6	2010	8	636.34	**0.0499**	95.114	3824559.56

Lastly, as I noted earlier, the Technical Support Document for EPA's proposed FIP provides support for the proposition that SCR efficiency should be greater than 90%.[48]

Given the already-substantial, and growing, body of evidence supporting a 90% control efficiency for SCR installations, EPA's BART analysis must demonstrate why the proposed SCRs for SJGS cannot achieve even a minimum of 90% NO_x reduction three years from now when SCR retrofits on older boilers are already achieving this removal efficiency. The record

[48] Dr. Fox's Report, p. 30-33.

contains no site-specific or technical factors that would preclude SCRs from achieving at least 90% NOx reduction at SJGS.

It is also important to note that most if not all of the examples above are SCR retrofits. Nonetheless, whether it is a retrofit or a new SCR, the catalyst starts out as new. For this reason, SCR efficiency distinctions between new and retrofit situations should not be an issue. To the extent that retrofit situations cause complexity in installation, that is properly accounted for in the cost calculation and the resulting cost-effectiveness analysis as provided in the technical support document. As explained below, the marginal increase in cost (beyond what is noted in the EPA proposal) to achieve a 0.035 lb/MMBtu NOx BART level will still be far lower than the typical BART cost-effectiveness thresholds employed by EPA itself (and other states)

Seventh, a comparable unit to SGJS has demonstrated a sustained level of NOx emissions at or below 0.035 lbs/MMBtu. This unit is Dynegy's Havana Unit 9 in Illinois. Table C below shows the monthly NOx emissions for this unit since 2002 (i.e., before SCR was installed). Although they vary somewhat, Havana Unit 9's NOx emissions were higher (i.e., closer to 0.3 lb/MMBtu) prior to 2005 or so – in fact, they were in the same range as current NOx emissions from the four units at SJGS. However, after 2005, NOx emissions from Havana Unit 9 have been generally in the 0.03-0.04 lb/MMBtu range. Again, please note that this is not driven by a low permit limit. In fact, its NOx limit is 0.1 lb/MMBtu.[49] Further, I provide the 30-day rolling average from this same unit for the first 6 months of 2010 for which data is now available. That is shown in Table D.

Table C – Monthly NOx Emissions Havana Unit 9

State	Facility	(ORISPL)	Unit	Year	Month	Op. Time (Hrs)	Avg. NOx Rate (lb/MMBtu)	NOx Tons	Heat Input (MMBtu)
IL	Havana	891	9	2002	1	567	0.29	297	2,054,441
IL	Havana	891	9	2002	2	549	0.27	275.4	2,104,459
IL	Havana	891	9	2002	3	744	0.34	525.1	3,086,432
IL	Havana	891	9	2002	4	643	0.30	393.2	2,645,211

[49] See Clean Air Act Permit Program (CAAPP) Permit issued to Dynegy for Havana, page 63 of the .pdf document. Although the expiration of this permit is September 29, 2010, I do not believe that its NOx level has changed. In any case, this limit was in effect through most of 2010.

IL	Havana	891	9	2002	5	504	0.27	248.7	1,853,411
IL	Havana	891	9	2002	6	720	0.29	346.2	2,578,451
IL	Havana	891	9	2002	7	578	0.27	339.9	2,564,496
IL	Havana	891	9	2002	8	722	0.27	429.2	3,237,564
IL	Havana	891	9	2002	9	720	0.28	374.7	2,852,941
IL	Havana	891	9	2002	10	517	0.28	231.1	1,827,321
IL	Havana	891	9	2002	11	321	0.24	123.8	1,107,955
IL	Havana	891	9	2002	12	663	0.25	316.4	2,600,894
IL	Havana	891	9	2003	1	724	0.23	319.3	2,929,516
IL	Havana	891	9	2003	2	671	0.26	339.9	2,711,616
IL	Havana	891	9	2003	3	734	0.27	380.3	2,901,131
IL	Havana	891	9	2003	4	557	0.24	267.9	2,217,912
IL	Havana	891	9	2003	5	662	0.29	269.7	2,102,807
IL	Havana	891	9	2003	6	653	0.30	295.8	2,139,798
IL	Havana	891	9	2003	7	744	0.29	347.2	2,589,699
IL	Havana	891	9	2003	8	743	0.11	123.7	2,767,163
IL	Havana	891	9	2003	9	596	0.23	170.7	1,776,665
IL	Havana	891	9	2003	10	0			
IL	Havana	891	9	2003	11	545	0.29	223.1	1,630,914
IL	Havana	891	9	2003	12	667	0.26	296.9	2,328,738
IL	Havana	891	9	2004	1	651	0.25	315	2,518,685
IL	Havana	891	9	2004	2	664	0.26	373.1	2,807,824
IL	Havana	891	9	2004	3	700	0.25	308.6	2,482,853
IL	Havana	891	9	2004	4	669	0.30	292.1	2,049,551
IL	Havana	891	9	2004	5	598	0.26	235.3	1,975,620
IL	Havana	891	9	2004	6	680	0.09	59.8	2,161,429
IL	Havana	891	9	2004	7	554	0.07	47.2	1,861,304
IL	Havana	891	9	2004	8	305	0.10	35.1	941,451
IL	Havana	891	9	2004	9	321	0.09	31.4	1,119,182
IL	Havana	891	9	2004	10	435	0.24	192.3	1,634,146
IL	Havana	891	9	2004	11	482	0.21	190.5	1,812,311
IL	Havana	891	9	2004	12	469	0.15	119.2	1,830,562
IL	Havana	891	9	2005	1	661	0.04	38.9	2,846,936
IL	Havana	891	9	2005	2	630	0.03	33.1	2,910,177
IL	Havana	891	9	2005	3	631	0.03	33.2	2,853,786
IL	Havana	891	9	2005	4	720	0.03	50.4	3,434,343
IL	Havana	891	9	2005	5	663	0.04	45.5	2,688,112
IL	Havana	891	9	2005	6	650	0.03	35.9	2,903,373
IL	Havana	891	9	2005	7	682	0.03	45.3	3,091,860
IL	Havana	891	9	2005	8	681	0.03	47.3	3,122,063
IL	Havana	891	9	2005	9	718	0.02	35.8	3,103,243
IL	Havana	891	9	2005	10	663	0.05	54.4	2,529,132
IL	Havana	891	9	2005	11	667	0.07	67.8	2,080,356
IL	Havana	891	9	2005	12	670	0.06	78.9	2,742,854
IL	Havana	891	9	2006	1	690	0.06	78.3	2,910,609
IL	Havana	891	9	2006	2	589	0.06	74.4	2,553,940
IL	Havana	891	9	2006	3	634	0.07	74	2,284,137
IL	Havana	891	9	2006	4	167	0.07	20.7	633,944
IL	Havana	891	9	2006	5	381	0.04	21.7	1,476,516
IL	Havana	891	9	2006	6	634	0.04	37.1	2,437,259
IL	Havana	891	9	2006	7	618	0.03	37.7	2,601,714
IL	Havana	891	9	2006	8	518	0.04	33.9	2,400,652
IL	Havana	891	9	2006	9	594	0.04	39.1	2,649,503
IL	Havana	891	9	2006	10	744	0.05	95.5	3,638,487
IL	Havana	891	9	2006	11	631	0.06	74.4	2,787,477

IL	Havana	891	9	2006	12	643	0.06	84.1	2,939,973
IL	Havana	891	9	2007	1	684	0.05	89.3	3,358,460
IL	Havana	891	9	2007	2	585	0.06	70.1	2,513,107
IL	Havana	891	9	2007	3	662	0.05	80.3	3,166,339
IL	Havana	891	9	2007	4	720	0.05	98.7	3,605,142
IL	Havana	891	9	2007	5	362	0.02	20.7	1,677,941
IL	Havana	891	9	2007	6	588	0.03	37.4	2,652,974
IL	Havana	891	9	2007	7	680	0.03	40	3,206,354
IL	Havana	891	9	2007	8	710	0.03	46.7	3,446,700
IL	Havana	891	9	2007	9	674	0.04	49	3,050,575
IL	Havana	891	9	2007	10	727	0.06	101	3,376,456
IL	Havana	891	9	2007	11	646	0.06	75	2,799,162
IL	Havana	891	9	2007	12	649	0.06	79.9	2,923,254
IL	Havana	891	9	2008	1	404	0.06	53	1,843,020
IL	Havana	891	9	2008	2	400	0.05	39	1,671,924
IL	Havana	891	9	2008	3	598	0.04	42.2	2,083,249
IL	Havana	891	9	2008	4	720	0.04	66.7	3,034,083
IL	Havana	891	9	2008	5	545	0.03	27.5	2,077,250
IL	Havana	891	9	2008	6	628	0.03	36.5	2,697,715
IL	Havana	891	9	2008	7	684	0.03	43.7	3,015,470
IL	Havana	891	9	2008	8	684	0.03	39.3	3,063,579
IL	Havana	891	9	2008	9	720	0.02	33.9	2,964,299
IL	Havana	891	9	2008	10	626	0.06	72.5	2,594,959
IL	Havana	891	9	2008	11	634	0.07	85.9	2,721,664
IL	Havana	891	9	2008	12	695	0.06	89.1	2,990,820
IL	Havana	891	9	2009	1	655	0.06	79.1	2,816,723
IL	Havana	891	9	2009	2	625	0.03	48.2	2,836,272
IL	Havana	891	9	2009	3	424	0.03	24	1,718,822
IL	Havana	891	9	2009	4	0	-		
IL	Havana	891	9	2009	5	0	-		
IL	Havana	891	9	2009	6	450	0.05	27.5	1,734,194
IL	Havana	891	9	2009	7	711	0.03	32.1	2,354,361
IL	Havana	891	9	2009	8	622	0.03	30.1	2,104,968
IL	Havana	891	9	2009	9	599	0.04	23.4	1,545,766
IL	Havana	891	9	2009	10	744	0.03	34.6	2,467,119
IL	Havana	891	9	2009	11	556	0.04	26.1	1,691,911
IL	Havana	891	9	2009	12	743	0.03	48	3,004,158

As discussed above, I show next the 30-day rolling NOx emissions from this same unit for the full year beginning July 1, 2009 through June 30, 2010. It is clear from the last column in Table D below that this unit, which had pre-SCR NOx emission levels in the same range of the SJGS's current NOx emissions is now able to achieve a NOx level of 0.035 lb/MMBtu or lower on a 30-day rolling average basis.

Table D – 30-Day Rolling Average NOx Emissions

Havana Unit 9 (July 1, 2009 – June 30, 2010)

State	Facility	ORISPL	Unit	Year	Day	Op. Time (Hrs)	Avg. NOx Rate (lb/mmBtu)	NOx Tons	Heat Input (mmBtu)	30-Day Rolling NOx (lb/MMBtu)
IL	Havana	891	9	2009	07/01/2009	24	0.03	1	69,437	
IL	Havana	891	9	2009	07/02/2009	24	0.02	1.1	88,301	
IL	Havana	891	9	2009	07/03/2009	8	0.07	0.2	12,940	
IL	Havana	891	9	2009	07/04/2009	7	0.15	0.3	3,088	
IL	Havana	891	9	2009	07/05/2009	24	0.03	1	72,379	
IL	Havana	891	9	2009	07/06/2009	24	0.02	0.9	86,419	
IL	Havana	891	9	2009	07/07/2009	24	0.02	0.9	88,797	
IL	Havana	891	9	2009	07/08/2009	24	0.03	1	70,487	
IL	Havana	891	9	2009	07/09/2009	24	0.03	1.1	85,476	
IL	Havana	891	9	2009	07/10/2009	24	0.02	1.1	92,502	
IL	Havana	891	9	2009	07/11/2009	24	0.03	1.1	91,731	
IL	Havana	891	9	2009	07/12/2009	24	0.03	1	77,156	
IL	Havana	891	9	2009	07/13/2009	24	0.03	1.1	85,684	
IL	Havana	891	9	2009	07/14/2009	24	0.03	1	80,823	
IL	Havana	891	9	2009	07/15/2009	24	0.03	1.1	92,770	
IL	Havana	891	9	2009	07/16/2009	24	0.02	0.8	79,912	
IL	Havana	891	9	2009	07/17/2009	24	0.02	0.6	52,995	
IL	Havana	891	9	2009	07/18/2009	24	0.02	0.6	47,702	
IL	Havana	891	9	2009	07/19/2009	24	0.02	0.7	61,734	
IL	Havana	891	9	2009	07/20/2009	24	0.03	1.2	87,653	
IL	Havana	891	9	2009	07/21/2009	24	0.03	1.3	85,869	
IL	Havana	891	9	2009	07/22/2009	24	0.03	1.4	86,683	
IL	Havana	891	9	2009	07/23/2009	24	0.03	1.5	95,736	
IL	Havana	891	9	2009	07/24/2009	24	0.04	1.7	89,128	
IL	Havana	891	9	2009	07/25/2009	24	0.03	1.1	79,408	
IL	Havana	891	9	2009	07/26/2009	24	0.03	1.1	74,541	
IL	Havana	891	9	2009	07/27/2009	24	0.03	1.3	86,189	
IL	Havana	891	9	2009	07/28/2009	24	0.03	1.4	82,400	
IL	Havana	891	9	2009	07/29/2009	24	0.03	1.3	87,500	
IL	Havana	891	9	2009	07/30/2009	24	0.03	1.1	78,212	0.027
IL	Havana	891	9	2009	07/31/2009	24	0.03	1.1	80,711	0.027
IL	Havana	891	9	2009	08/01/2009	24	0.03	0.6	42,497	0.027
IL	Havana	891	9	2009	08/02/2009	24	0.03	1	60,759	0.027
IL	Havana	891	9	2009	08/03/2009	24	0.03	1	86,055	0.027
IL	Havana	891	9	2009	08/04/2009	24	0.02	1.1	94,385	0.027
IL	Havana	891	9	2009	08/05/2009	24	0.02	1	84,820	0.027
IL	Havana	891	9	2009	08/06/2009	24	0.03	1.3	84,914	0.027
IL	Havana	891	9	2009	08/07/2009	24	0.03	1.2	79,219	0.027
IL	Havana	891	9	2009	08/08/2009	24	0.03	1.2	77,501	0.028

IL	Havana	891	9	2009	08/09/2009	24	0.03	1.4	90,580	0.028
IL	Havana	891	9	2009	08/10/2009	24	0.03	1.4	96,437	0.028
IL	Havana	891	9	2009	08/11/2009	24	0.03	1.3	96,583	0.028
IL	Havana	891	9	2009	08/12/2009	24	0.03	1.3	95,021	0.028
IL	Havana	891	9	2009	08/13/2009	24	0.03	1.1	87,112	0.028
IL	Havana	891	9	2009	08/14/2009	24	0.03	1.2	92,890	0.028
IL	Havana	891	9	2009	08/15/2009	24	0.03	1.1	84,670	0.028
IL	Havana	891	9	2009	08/16/2009	24	0.02	1	84,853	0.028
IL	Havana	891	9	2009	08/17/2009	24	0.02	1.1	98,790	0.028
IL	Havana	891	9	2009	08/18/2009	24	0.03	1.3	102,874	0.028
IL	Havana	891	9	2009	08/19/2009	24	0.03	1.6	92,096	0.029
IL	Havana	891	9	2009	08/20/2009	24	0.03	1.3	87,079	0.029
IL	Havana	891	9	2009	08/21/2009	22	0.05	1.3	65,009	0.029
IL	Havana	891	9	2009	08/22/2009	0				0.029
IL	Havana	891	9	2009	08/23/2009	2	0.01	0	391	0.028
IL	Havana	891	9	2009	08/24/2009	19	0.08	0.8	34,468	0.029
IL	Havana	891	9	2009	08/25/2009	24	0.04	1.8	82,449	0.029
IL	Havana	891	9	2009	08/26/2009	24	0.02	0.8	68,939	0.029
IL	Havana	891	9	2009	08/27/2009	24	0.02	0.6	54,090	0.028
IL	Havana	891	9	2009	08/28/2009	24	0.04	1.2	79,335	0.028
IL	Havana	891	9	2009	08/29/2009	0				0.028
IL	Havana	891	9	2009	08/30/2009	0				0.029
IL	Havana	891	9	2009	08/31/2009	4	0.10	0.1	1,153	0.029
IL	Havana	891	9	2009	09/01/2009	24	0.03	0.5	43,947	0.028
IL	Havana	891	9	2009	09/02/2009	24	0.03	1	77,046	0.028
IL	Havana	891	9	2009	09/03/2009	24	0.02	0.9	74,425	0.029
IL	Havana	891	9	2009	09/04/2009	24	0.04	0.9	61,373	0.029
IL	Havana	891	9	2009	09/05/2009	1	0.31	0	147	0.029
IL	Havana	891	9	2009	09/06/2009	1	0.12	0	43	0.029
IL	Havana	891	9	2009	09/07/2009	22	0.12	0.8	22,322	0.029
IL	Havana	891	9	2009	09/08/2009	24	0.03	1	69,813	0.029
IL	Havana	891	9	2009	09/09/2009	24	0.03	1	70,972	0.029
IL	Havana	891	9	2009	09/10/2009	24	0.03	1	67,167	0.029
IL	Havana	891	9	2009	09/11/2009	24	0.03	1.2	76,717	0.029
IL	Havana	891	9	2009	09/12/2009	24	0.03	1	58,274	0.030
IL	Havana	891	9	2009	09/13/2009	24	0.03	0.9	63,604	0.030
IL	Havana	891	9	2009	09/14/2009	24	0.03	1	72,545	0.030
IL	Havana	891	9	2009	09/15/2009	24	0.03	1.1	84,057	0.030
IL	Havana	891	9	2009	09/16/2009	18	0.04	0.5	32,046	0.031
IL	Havana	891	9	2009	09/17/2009	24	0.03	0.7	61,192	0.031
IL	Havana	891	9	2009	09/18/2009	24	0.03	1	74,474	0.030

IL	Havana	891	9	2009	09/19/2009	24	0.03	0.4	26,431	0.030
IL	Havana	891	9	2009	09/20/2009	24	0.02	0.5	37,350	0.030
IL	Havana	891	9	2009	09/21/2009	24	0.03	1	68,948	0.030
IL	Havana	891	9	2009	09/22/2009	24	0.03	1.3	74,608	0.030
IL	Havana	891	9	2009	09/23/2009	24	0.03	1.2	73,318	0.030
IL	Havana	891	9	2009	09/24/2009	24	0.03	1.4	71,622	0.029
IL	Havana	891	9	2009	09/25/2009	0	0.00	0	3	0.030
IL	Havana	891	9	2009	09/26/2009	0				0.030
IL	Havana	891	9	2009	09/27/2009	4	0.10	0	477	0.030
IL	Havana	891	9	2009	09/28/2009	24	0.07	1	44,073	0.030
IL	Havana	891	9	2009	09/29/2009	24	0.03	1.1	69,911	0.030
IL	Havana	891	9	2009	09/30/2009	24	0.02	0.9	68,865	0.030
IL	Havana	891	9	2009	10/01/2009	24	0.03	0.7	51,770	0.030
IL	Havana	891	9	2009	10/02/2009	24	0.03	0.8	53,348	0.030
IL	Havana	891	9	2009	10/03/2009	24	0.03	0.8	49,737	0.031
IL	Havana	891	9	2009	10/04/2009	24	0.03	0.6	48,653	0.031
IL	Havana	891	9	2009	10/05/2009	24	0.03	1	73,541	0.031
IL	Havana	891	9	2009	10/06/2009	24	0.03	0.9	57,585	0.031
IL	Havana	891	9	2009	10/07/2009	24	0.03	1	54,683	0.030
IL	Havana	891	9	2009	10/08/2009	24	0.03	1.1	69,871	0.030
IL	Havana	891	9	2009	10/09/2009	24	0.04	1.3	74,827	0.031
IL	Havana	891	9	2009	10/10/2009	24	0.02	0.6	42,379	0.031
IL	Havana	891	9	2009	10/11/2009	24	0.03	0.9	62,204	0.030
IL	Havana	891	9	2009	10/12/2009	24	0.02	1	75,903	0.030
IL	Havana	891	9	2009	10/13/2009	24	0.03	1	75,526	0.030
IL	Havana	891	9	2009	10/14/2009	24	0.03	1.2	84,023	0.030
IL	Havana	891	9	2009	10/15/2009	24	0.03	1.4	100,068	0.030
IL	Havana	891	9	2009	10/16/2009	24	0.03	1.5	113,106	0.030
IL	Havana	891	9	2009	10/17/2009	24	0.03	1.6	109,361	0.030
IL	Havana	891	9	2009	10/18/2009	24	0.03	1.4	96,738	0.030
IL	Havana	891	9	2009	10/19/2009	24	0.03	1.5	101,277	0.030
IL	Havana	891	9	2009	10/20/2009	24	0.03	1.3	103,705	0.030
IL	Havana	891	9	2009	10/21/2009	24	0.03	1.5	104,614	0.030
IL	Havana	891	9	2009	10/22/2009	24	0.03	1.4	94,971	0.030
IL	Havana	891	9	2009	10/23/2009	24	0.03	1.3	89,989	0.030
IL	Havana	891	9	2009	10/24/2009	24	0.03	1.3	92,125	0.029
IL	Havana	891	9	2009	10/25/2009	24	0.03	1.3	81,125	0.029
IL	Havana	891	9	2009	10/26/2009	24	0.02	1	85,150	0.029
IL	Havana	891	9	2009	10/27/2009	24	0.02	1.1	89,330	0.029
IL	Havana	891	9	2009	10/28/2009	24	0.02	1.1	90,389	0.028
IL	Havana	891	9	2009	10/29/2009	24	0.02	1	86,085	0.028

IL	Havana	891	9	2009	10/30/2009	24	0.03	1.1	79,168	0.028
IL	Havana	891	9	2009	10/31/2009	24	0.03	0.9	75,871	0.028
IL	Havana	891	9	2009	11/01/2009	24	0.02	0.9	72,884	0.028
IL	Havana	891	9	2009	11/02/2009	24	0.03	1.1	75,413	0.028
IL	Havana	891	9	2009	11/03/2009	24	0.03	1.2	81,207	0.028
IL	Havana	891	9	2009	11/04/2009	24	0.03	1.4	90,114	0.028
IL	Havana	891	9	2009	11/05/2009	24	0.03	1.4	84,941	0.028
IL	Havana	891	9	2009	11/06/2009	15	0.03	0.6	37,762	0.028
IL	Havana	891	9	2009	11/07/2009	0				0.028
IL	Havana	891	9	2009	11/08/2009	4	0.06	0	590	0.028
IL	Havana	891	9	2009	11/09/2009	24	0.07	1.3	66,494	0.028
IL	Havana	891	9	2009	11/10/2009	24	0.03	1.3	79,655	0.028
IL	Havana	891	9	2009	11/11/2009	24	0.03	1.1	75,492	0.028
IL	Havana	891	9	2009	11/12/2009	24	0.03	1.4	84,783	0.029
IL	Havana	891	9	2009	11/13/2009	24	0.03	1.1	72,724	0.029
IL	Havana	891	9	2009	11/14/2009	24	0.03	1.3	76,192	0.029
IL	Havana	891	9	2009	11/15/2009	24	0.05	1.4	63,049	0.029
IL	Havana	891	9	2009	11/16/2009	24	0.04	0.9	55,837	0.029
IL	Havana	891	9	2009	11/17/2009	24	0.02	0.8	64,903	0.029
IL	Havana	891	9	2009	11/18/2009	24	0.03	0.9	68,152	0.029
IL	Havana	891	9	2009	11/19/2009	24	0.03	1.1	86,041	0.029
IL	Havana	891	9	2009	11/20/2009	24	0.03	1.2	95,942	0.029
IL	Havana	891	9	2009	11/21/2009	24	0.03	0.7	51,496	0.029
IL	Havana	891	9	2009	11/22/2009	24	0.02	0.8	77,763	0.029
IL	Havana	891	9	2009	11/23/2009	24	0.03	1.1	83,654	0.029
IL	Havana	891	9	2009	11/24/2009	24	0.05	1.3	67,696	0.029
IL	Havana	891	9	2009	11/25/2009	2	0.26	0.3	1,904	0.029
IL	Havana	891	9	2009	11/26/2009	0				0.029
IL	Havana	891	9	2009	11/27/2009	0				0.030
IL	Havana	891	9	2009	11/28/2009	0				0.030
IL	Havana	891	9	2009	11/29/2009	7	0.10	0.2	3,155	0.030
IL	Havana	891	9	2009	11/30/2009	24	0.05	1.2	74,070	0.031
IL	Havana	891	9	2009	12/01/2009	24	0.02	1	82,018	0.031
IL	Havana	891	9	2009	12/02/2009	24	0.03	1.2	90,823	0.031
IL	Havana	891	9	2009	12/03/2009	24	0.03	1.3	98,285	0.030
IL	Havana	891	9	2009	12/04/2009	24	0.03	1.5	109,020	0.030
IL	Havana	891	9	2009	12/05/2009	24	0.03	1.5	113,766	0.030
IL	Havana	891	9	2009	12/06/2009	24	0.02	1.2	99,188	0.029
IL	Havana	891	9	2009	12/07/2009	24	0.03	1.2	88,305	0.029
IL	Havana	891	9	2009	12/08/2009	24	0.03	1.2	83,537	0.029
IL	Havana	891	9	2009	12/09/2009	24	0.03	1.3	85,577	0.029

IL	Havana	891	9	2009	12/10/2009	24	0.03	1.6	92,130	0.029
IL	Havana	891	9	2009	12/11/2009	24	0.03	1.4	87,661	0.029
IL	Havana	891	9	2009	12/12/2009	24	0.03	1.5	89,500	0.029
IL	Havana	891	9	2009	12/13/2009	24	0.03	1.3	83,608	0.029
IL	Havana	891	9	2009	12/14/2009	24	0.03	1.1	73,838	0.029
IL	Havana	891	9	2009	12/15/2009	24	0.03	1.3	91,868	0.029
IL	Havana	891	9	2009	12/16/2009	23	0.03	1.2	95,478	0.028
IL	Havana	891	9	2009	12/17/2009	24	0.13	7.2	112,731	0.034
IL	Havana	891	9	2009	12/18/2009	24	0.03	1.7	112,046	0.034
IL	Havana	891	9	2009	12/19/2009	24	0.02	1.2	107,772	0.033
IL	Havana	891	9	2009	12/20/2009	24	0.03	1.6	115,432	0.034
IL	Havana	891	9	2009	12/21/2009	24	0.03	1.7	118,588	0.033
IL	Havana	891	9	2009	12/22/2009	24	0.03	1.6	117,370	0.034
IL	Havana	891	9	2009	12/23/2009	24	0.03	1.3	96,978	0.034
IL	Havana	891	9	2009	12/24/2009	24	0.04	1.3	73,221	0.033
IL	Havana	891	9	2009	12/25/2009	24	0.04	0.5	29,708	0.033
IL	Havana	891	9	2009	12/26/2009	24	0.03	1.4	97,204	0.033
IL	Havana	891	9	2009	12/27/2009	24	0.03	1.9	109,196	0.033
IL	Havana	891	9	2009	12/28/2009	24	0.03	1.6	108,522	0.033
IL	Havana	891	9	2009	12/29/2009	24	0.03	1.6	116,104	0.033
IL	Havana	891	9	2009	12/30/2009	24	0.03	1.6	115,186	0.032
IL	Havana	891	9	2009	12/31/2009	24	0.02	1.3	109,499	0.032
IL	Havana	891	9	2010	01/01/2010	24	0.03	1.7	114,554	0.032
IL	Havana	891	9	2010	01/02/2010	24	0.04	2.3	113,266	0.033
IL	Havana	891	9	2010	01/03/2010	24	0.04	2	112,675	0.033
IL	Havana	891	9	2010	01/04/2010	24	0.03	1.7	112,077	0.033
IL	Havana	891	9	2010	01/05/2010	24	0.04	1.9	110,012	0.034
IL	Havana	891	9	2010	01/06/2010	24	0.03	1.7	109,564	0.034
IL	Havana	891	9	2010	01/07/2010	24	0.03	1.5	107,824	0.034
IL	Havana	891	9	2010	01/08/2010	24	0.03	1.8	109,237	0.034
IL	Havana	891	9	2010	01/09/2010	24	0.04	2	111,363	0.034
IL	Havana	891	9	2010	01/10/2010	24	0.03	1.5	105,994	0.034
IL	Havana	891	9	2010	01/11/2010	24	0.03	1.6	104,949	0.034
IL	Havana	891	9	2010	01/12/2010	24	0.03	1.4	107,667	0.033
IL	Havana	891	9	2010	01/13/2010	24	0.03	1	62,094	0.034
IL	Havana	891	9	2010	01/14/2010	24	0.03	1.3	86,458	0.034
IL	Havana	891	9	2010	01/15/2010	24	0.03	1.6	112,134	0.034
IL	Havana	891	9	2010	01/16/2010	24	0.03	1.6	110,402	0.030
IL	Havana	891	9	2010	01/17/2010	24	0.03	1.5	99,866	0.030
IL	Havana	891	9	2010	01/18/2010	24	0.03	1.7	112,800	0.030
IL	Havana	891	9	2010	01/19/2010	24	0.03	1.7	112,731	0.030

IL	Havana	891	9	2010	01/20/2010	24	0.03	1.4	95,910	0.030
IL	Havana	891	9	2010	01/21/2010	24	0.03	1.8	113,330	0.031
IL	Havana	891	9	2010	01/22/2010	24	0.03	1.6	108,423	0.031
IL	Havana	891	9	2010	01/23/2010	24	0.03	1.3	86,922	0.031
IL	Havana	891	9	2010	01/24/2010	24	0.02	0.9	76,231	0.030
IL	Havana	891	9	2010	01/25/2010	24	0.03	1.3	103,565	0.030
IL	Havana	891	9	2010	01/26/2010	24	0.03	1.6	113,507	0.030
IL	Havana	891	9	2010	01/27/2010	24	0.03	1.4	106,998	0.030
IL	Havana	891	9	2010	01/28/2010	24	0.03	1.6	108,580	0.030
IL	Havana	891	9	2010	01/29/2010	24	0.03	1.5	110,579	0.030
IL	Havana	891	9	2010	01/30/2010	24	0.03	1.6	114,789	0.030
IL	Havana	891	9	2010	01/31/2010	24	0.03	1.6	114,899	0.030
IL	Havana	891	9	2010	02/01/2010	24	0.03	1.7	112,076	0.030
IL	Havana	891	9	2010	02/02/2010	1	0.32	0.2	1,089	0.030
IL	Havana	891	9	2010	02/03/2010	0				0.030
IL	Havana	891	9	2010	02/04/2010	19	0.08	0.9	41,890	0.030
IL	Havana	891	9	2010	02/05/2010	24	0.03	1.6	111,997	0.029
IL	Havana	891	9	2010	02/06/2010	24	0.03	1.6	111,787	0.029
IL	Havana	891	9	2010	02/07/2010	24	0.03	1.5	107,695	0.029
IL	Havana	891	9	2010	02/08/2010	24	0.03	1.6	107,079	0.029
IL	Havana	891	9	2010	02/09/2010	24	0.03	1.5	102,394	0.029
IL	Havana	891	9	2010	02/10/2010	24	0.03	1.4	104,278	0.029
IL	Havana	891	9	2010	02/11/2010	24	0.03	1.3	103,793	0.029
IL	Havana	891	9	2010	02/12/2010	24	0.03	1.4	101,223	0.029
IL	Havana	891	9	2010	02/13/2010	24	0.02	1.3	100,744	0.029
IL	Havana	891	9	2010	02/14/2010	24	0.02	1.2	96,591	0.029
IL	Havana	891	9	2010	02/15/2010	24	0.03	1.3	96,262	0.028
IL	Havana	891	9	2010	02/16/2010	24	0.03	1.4	93,008	0.028
IL	Havana	891	9	2010	02/17/2010	24	0.03	1.3	89,359	0.028
IL	Havana	891	9	2010	02/18/2010	24	0.03	1.4	87,510	0.028
IL	Havana	891	9	2010	02/19/2010	1	0.27	0.1	505	0.029
IL	Havana	891	9	2010	02/20/2010	0				0.028
IL	Havana	891	9	2010	02/21/2010	0				0.028
IL	Havana	891	9	2010	02/22/2010	0				0.028
IL	Havana	891	9	2010	02/23/2010	6	0.11	0.1	1,579	0.029
IL	Havana	891	9	2010	02/24/2010	24	0.09	1.3	68,619	0.029
IL	Havana	891	9	2010	02/25/2010	24	0.03	1.4	100,916	0.029
IL	Havana	891	9	2010	02/26/2010	24	0.03	1.2	98,059	0.029
IL	Havana	891	9	2010	02/27/2010	24	0.03	1.3	98,629	0.029
IL	Havana	891	9	2010	02/28/2010	24	0.03	1.2	93,754	0.029
IL	Havana	891	9	2010	03/01/2010	24	0.03	1.5	100,291	0.029

IL	Havana	891	9	2010	03/02/2010	24	0.03	1.6	103,328	0.029
IL	Havana	891	9	2010	03/03/2010	24	0.03	1.4	101,851	0.029
IL	Havana	891	9	2010	03/04/2010	24	0.03	1.1	85,086	0.029
IL	Havana	891	9	2010	03/05/2010	24	0.03	1.3	100,233	0.028
IL	Havana	891	9	2010	03/06/2010	24	0.03	1.3	100,737	0.028
IL	Havana	891	9	2010	03/07/2010	24	0.03	1.4	99,512	0.028
IL	Havana	891	9	2010	03/08/2010	24	0.03	1.2	99,750	0.028
IL	Havana	891	9	2010	03/09/2010	24	0.03	1.3	98,769	0.028
IL	Havana	891	9	2010	03/10/2010	24	0.04	1.4	87,104	0.028
IL	Havana	891	9	2010	03/11/2010	24	0.03	1.1	71,611	0.028
IL	Havana	891	9	2010	03/12/2010	24	0.03	1.5	99,092	0.028
IL	Havana	891	9	2010	03/13/2010	24	0.03	1.5	99,244	0.028
IL	Havana	891	9	2010	03/14/2010	24	0.02	1.2	96,796	0.028
IL	Havana	891	9	2010	03/15/2010	24	0.02	1.2	98,152	0.028
IL	Havana	891	9	2010	03/16/2010	24	0.03	1.4	100,318	0.028
IL	Havana	891	9	2010	03/17/2010	24	0.03	1.3	84,902	0.028
IL	Havana	891	9	2010	03/18/2010	24	0.03	1.4	98,432	0.028
IL	Havana	891	9	2010	03/19/2010	24	0.03	1.3	95,902	0.028
IL	Havana	891	9	2010	03/20/2010	24	0.03	1.5	101,642	0.028
IL	Havana	891	9	2010	03/21/2010	24	0.03	1.2	84,887	0.028
IL	Havana	891	9	2010	03/22/2010	24	0.03	1.5	103,142	0.028
IL	Havana	891	9	2010	03/23/2010	24	0.03	1.3	94,509	0.028
IL	Havana	891	9	2010	03/24/2010	24	0.03	1.1	82,293	0.028
IL	Havana	891	9	2010	03/25/2010	24	0.03	1.1	83,098	0.028
IL	Havana	891	9	2010	03/26/2010	24	0.03	1.6	101,053	0.028
IL	Havana	891	9	2010	03/27/2010	24	0.03	1.2	87,153	0.028
IL	Havana	891	9	2010	03/28/2010	24	0.03	1.1	82,059	0.028
IL	Havana	891	9	2010	03/29/2010	24	0.03	1.3	103,722	0.028
IL	Havana	891	9	2010	03/30/2010	24	0.02	1	91,325	0.028
IL	Havana	891	9	2010	03/31/2010	24	0.03	1.3	78,966	0.028
IL	Havana	891	9	2010	04/01/2010	24	0.03	1.1	77,784	0.028
IL	Havana	891	9	2010	04/02/2010	2	0.25	0.1	785	0.028
IL	Havana	891	9	2010	04/03/2010	0				0.028
IL	Havana	891	9	2010	04/04/2010	7	0.12	0.2	2,172	0.028
IL	Havana	891	9	2010	04/05/2010	24	0.06	1.3	77,605	0.028
IL	Havana	891	9	2010	04/06/2010	24	0.02	1.1	95,100	0.028
IL	Havana	891	9	2010	04/07/2010	24	0.02	1	76,721	0.028
IL	Havana	891	9	2010	04/08/2010	22	0.05	1	59,759	0.028
IL	Havana	891	9	2010	04/09/2010	8	0.06	0.5	26,309	0.028
IL	Havana	891	9	2010	04/10/2010	1	0.07	0	67	0.028
IL	Havana	891	9	2010	04/11/2010	24	0.09	1.2	55,008	0.029

IL	Havana	891	9	2010	04/12/2010	24	0.02	1.1	95,674	0.028
IL	Havana	891	9	2010	04/13/2010	24	0.03	1.4	107,933	0.028
IL	Havana	891	9	2010	04/14/2010	24	0.03	1.4	104,977	0.028
IL	Havana	891	9	2010	04/15/2010	24	0.03	1.4	102,251	0.028
IL	Havana	891	9	2010	04/16/2010	24	0.03	1.3	86,629	0.028
IL	Havana	891	9	2010	04/17/2010	23	0.04	1.3	88,830	0.028
IL	Havana	891	9	2010	04/18/2010	24	0.02	1.3	117,895	0.028
IL	Havana	891	9	2010	04/19/2010	24	0.03	1.6	116,639	0.028
IL	Havana	891	9	2010	04/20/2010	24	0.03	1.4	110,939	0.028
IL	Havana	891	9	2010	04/21/2010	24	0.03	1.6	107,622	0.028
IL	Havana	891	9	2010	04/22/2010	24	0.03	1.5	97,830	0.028
IL	Havana	891	9	2010	04/23/2010	24	0.03	1.2	79,672	0.028
IL	Havana	891	9	2010	04/24/2010	24	0.03	1	70,855	0.028
IL	Havana	891	9	2010	04/25/2010	24	0.03	0.9	56,580	0.028
IL	Havana	891	9	2010	04/26/2010	24	0.03	1.2	84,322	0.028
IL	Havana	891	9	2010	04/27/2010	24	0.03	1.3	86,865	0.028
IL	Havana	891	9	2010	04/28/2010	24	0.02	1	85,573	0.028
IL	Havana	891	9	2010	04/29/2010	24	0.03	1.2	76,307	0.029
IL	Havana	891	9	2010	04/30/2010	24	0.02	1.1	92,432	0.028
IL	Havana	891	9	2010	05/01/2010	24	0.02	1.1	93,628	0.028
IL	Havana	891	9	2010	05/02/2010	24	0.03	1.3	87,109	0.028
IL	Havana	891	9	2010	05/03/2010	24	0.06	2.8	93,511	0.029
IL	Havana	891	9	2010	05/04/2010	24	0.03	1.6	97,864	0.029
IL	Havana	891	9	2010	05/05/2010	24	0.03	1.5	101,419	0.029
IL	Havana	891	9	2010	05/06/2010	24	0.03	1.5	117,989	0.029
IL	Havana	891	9	2010	05/07/2010	24	0.03	1.8	125,522	0.029
IL	Havana	891	9	2010	05/08/2010	20	0.07	1.2	70,775	0.029
IL	Havana	891	9	2010	05/09/2010	24	0.02	1	120,217	0.029
IL	Havana	891	9	2010	05/10/2010	24	0.03	1.5	101,227	0.029
IL	Havana	891	9	2010	05/11/2010	24	0.03	1.5	117,249	0.028
IL	Havana	891	9	2010	05/12/2010	24	0.03	1.7	126,652	0.028
IL	Havana	891	9	2010	05/13/2010	24	0.03	1.7	122,090	0.028
IL	Havana	891	9	2010	05/14/2010	24	0.03	1.8	125,255	0.029
IL	Havana	891	9	2010	05/15/2010	24	0.02	1.5	129,490	0.028
IL	Havana	891	9	2010	05/16/2010	24	0.02	1.5	123,378	0.028
IL	Havana	891	9	2010	05/17/2010	24	0.03	1.6	124,066	0.028
IL	Havana	891	9	2010	05/18/2010	24	0.03	1.8	127,370	0.028
IL	Havana	891	9	2010	05/19/2010	24	0.03	1.6	123,597	0.028
IL	Havana	891	9	2010	05/20/2010	24	0.03	1.8	122,633	0.028
IL	Havana	891	9	2010	05/21/2010	20	0.03	1.6	96,577	0.028
IL	Havana	891	9	2010	05/22/2010	23	0.19	5.1	53,217	0.031

IL	Havana	891	9	2010	05/23/2010	24	0.04	1.1	57,860	0.031
IL	Havana	891	9	2010	05/24/2010	24	0.03	1	63,655	0.031
IL	Havana	891	9	2010	05/25/2010	24	0.03	1.1	67,111	0.032
IL	Havana	891	9	2010	05/26/2010	24	0.03	1.8	116,035	0.032
IL	Havana	891	9	2010	05/27/2010	24	0.03	1.8	114,356	0.032
IL	Havana	891	9	2010	05/28/2010	24	0.04	1.9	104,594	0.032
IL	Havana	891	9	2010	05/29/2010	24	0.04	1.8	103,668	0.032
IL	Havana	891	9	2010	05/30/2010	24	0.04	1.6	97,811	0.032
IL	Havana	891	9	2010	05/31/2010	24	0.03	1.9	119,962	0.033
IL	Havana	891	9	2010	06/01/2010	24	0.03	1.7	118,193	0.033
IL	Havana	891	9	2010	06/02/2010	24	0.03	1.8	121,577	0.032
IL	Havana	891	9	2010	06/03/2010	24	0.03	1.9	121,255	0.032
IL	Havana	891	9	2010	06/04/2010	24	0.03	1.8	120,008	0.032
IL	Havana	891	9	2010	06/05/2010	24	0.03	2	115,671	0.032
IL	Havana	891	9	2010	06/06/2010	24	0.04	1.6	91,067	0.032
IL	Havana	891	9	2010	06/07/2010	24	0.03	1.5	109,826	0.032
IL	Havana	891	9	2010	06/08/2010	24	0.04	2.1	116,560	0.033
IL	Havana	891	9	2010	06/09/2010	24	0.03	1.7	112,055	0.033
IL	Havana	891	9	2010	06/10/2010	24	0.03	1.7	114,716	0.033
IL	Havana	891	9	2010	06/11/2010	24	0.03	1	66,835	0.033
IL	Havana	891	9	2010	06/12/2010	24	0.03	1.2	82,232	0.033
IL	Havana	891	9	2010	06/13/2010	24	0.03	1.7	97,583	0.033
IL	Havana	891	9	2010	06/14/2010	24	0.03	1.8	120,952	0.034
IL	Havana	891	9	2010	06/15/2010	24	0.04	2.2	119,996	0.034
IL	Havana	891	9	2010	06/16/2010	24	0.04	2.2	120,689	0.035
IL	Havana	891	9	2010	06/17/2010	24	0.04	2	111,899	0.035
IL	Havana	891	9	2010	06/18/2010	24	0.03	2	117,242	0.035
IL	Havana	891	9	2010	06/19/2010	24	0.04	2.3	117,889	0.036
IL	Havana	891	9	2010	06/20/2010	24	0.04	1.8	102,407	0.036
IL	Havana	891	9	2010	06/21/2010	24	0.04	2	115,777	0.033
IL	Havana	891	9	2010	06/22/2010	24	0.03	1.7	118,096	0.033
IL	Havana	891	9	2010	06/23/2010	24	0.04	2.5	111,712	0.033
IL	Havana	891	9	2010	06/24/2010	24	0.03	2	120,026	0.033
IL	Havana	891	9	2010	06/25/2010	24	0.03	1.7	110,396	0.033
IL	Havana	891	9	2010	06/26/2010	24	0.03	1.8	114,708	0.033
IL	Havana	891	9	2010	06/27/2010	24	0.03	1.8	111,044	0.033
IL	Havana	891	9	2010	06/28/2010	24	0.03	1.9	110,824	0.033
IL	Havana	891	9	2010	06/29/2010	24	0.03	1.8	106,704	0.033
IL	Havana	891	9	2010	06/30/2010	24	0.03	1.6	95,043	0.033

Based on all of the above, it is my expert opinion that it is technically feasible for SCR to achieve an efficiency of at least 90%, and possibly as much as 94% or 95% efficiency.

E. NOx BART

I will now integrate the information discussed above. Basically, Table E below shows controlled NOx emissions estimates assuming the current 2009/2010 NOx emissions discussed above and applying various SCR efficiency values. These emissions estimates include a compliance margin that reflects the emissions variability observed in the 2009/2010 NOx data from these units.

Table E – NOx Levels with SCR, Including Startup and Shutdown

Summary of 30-Day Rolling NOx (lb/MMBtu) 2009-2010 and NOx with Expected SCR and Margin										
	UNIT 1	UNIT 2	UNIT 3	UNIT 4	Max	w/SCR 90%	w/SCR 91%	w/SCR 92%	w/SCR 93%	w/SCR 94%
Average	0.286	0.282	0.275	0.284	0.286	0.0286	0.0257	0.0229	0.0200	0.0172
Max	0.299	0.314	0.303	0.306	0.314	0.0314	0.0282	0.0251	0.0220	0.0188
StDev	0.006	0.035	0.023	0.007	0.035	0.0035	0.0031	0.0028	0.0024	0.0021
StDev/Avg	0.019	0.124	0.082	0.026	0.122	0.122	0.122	0.122	0.122	0.122
Max:Avg	1.047	1.111	1.100	1.077	1.111					
Average+20% Margin						0.0343	0.0309	0.0274	0.0240	0.0206

Columns 2-5 of the table simply summarize the current 30-day rolling average NOx data for each unit. As provided earlier, this includes the average and maximum data and also the standard deviation and the ratios of the standard deviation to average as well as the maximum to average. The latter are provided to show the variability in the 30-day average. Please note that this data includes all periods of operation, including startup and shutdown. The sixth column of the table shows the maximum of these values for all four units. Finally, the last several columns show the effect on NOx emissions by the specified SCR efficiency, ranging from 90 to 94%. The average and maximum values are lowered by the respective percentages. I have also scaled the expected standard deviation based on the ratio of the standard deviation to the average in the current case. Finally, I have also estimated an average that includes a 20% margin.

As can be seen in the table, under no circumstance does the maximum value exceed 0.0314 lb/MMBtu. Also, under no circumstance does the average+20% margin exceed 0.0343 lb/MMBtu. Again, it should be noted that these values are based on the maxima of the respective underlying values from all 4 units for 2009/2010 and for the 90% SCR case. As the SCR efficiency increases, these values become considerably lower. And, as discussed earlier, SJGS can further lower its boiler out emissions, providing even greater margin.

Thus, based on all of the above, I recommend a NOx BART level of 0.035 lb/MMBtu, on a 30-day rolling average basis, including startup and shutdown, effective in 3 years from finalization of the rule.

F. Cost and Cost Effectiveness

EPA's cost analysis, as discussed in the preamble, shows that the cost-effectiveness to achieve the 0.05 lb/MMBtu level ranges from $1,579/ton reduced for Unit 4 to $1,920/ton reduced for Unit 2.[50] The technical support document also mentions these values.[51] However, the supporting spreadsheets in Exhibit 1 to the TSD, do not match. Those spreadsheets indicate the following, slightly lower, cost effectiveness values: $1,805/ton (Unit 1), $1,877/ton (Unit 2), $1,481 (Unit 3) and $1,447 (Unit 4). Putting aside this slight discrepancy, I concur with EPA's cost-effectiveness analysis, as opposed to the cost-effectiveness values that were calculated by PNM for SCR. As shown in the technical support document for EPA's Proposed Rule, PNM's analysis contained numerous errors and unsupported assumptions.

I also note that the EPA calculated cost-effectiveness values could be lower still since the EPA calculations assume that each SCR would be installed separately without regard to the other SCRs. As a practical matter, depending on the procurement strategy used by PNM (i.e., installing SCR at all 4 units simultaneously as opposed to one at a time) will provide numerous opportunities for obtaining favorable contract terms (from vendors, suppliers, and engineering support, etc.), resulting in lower SCR costs and cost-effectiveness.

Clearly, lowering the BART limit from 0.05 lb/MMBtu to 0.035 lb/MMBtu would increase the tons of NOx reduced (and also further improve visibility), thereby improving cost-effectiveness, assuming costs stay the same. I realize, however, that the costs to achieve and maintain NOx levels at 0.035 lb/MMBtu will likely be greater than the costs to achieve and maintain the proposed 0.05 lb/MMBtu level. But, it is my opinion that the cost increases will not be significant.

The incremental costs to get from 0.05 to 0.035 lb/MMBtu are relatively low since the bulk of the costs associated with the SCR infrastructure have already been included in the cost estimate. The cost of infrastructure will not increase based on my conversations with vendors because: (i)

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[50] See Table 7 at 76 FR 502.
[51] See technical support document at Section H, page 28.

it is likely that less catalyst will be required (i.e., a 2x1 configuration as opposed to a 3x1 configuration); and (ii) a higher activity catalyst can likely be used (leading to less volume required) given the low sulfur and SO3 levels in the in-coming gas. Thus, the cost of the additional catalyst required, if any, should be very small or none. And, similarly, the costs for additional ammonia usage and more-frequent change-out of catalyst, if needed, are also not significant, given the other costs. Thus, while the costs may increase, as explained below, my analysis shows that these marginal cost increases will not significantly affect EPA's existing cost-effectiveness analysis. In order to assess how the cost-effectiveness may change, I followed the same methodology as in the EPA technical support document (the 0.05 lb/MMBtu case) and made two adjustments. I increased the ammonia usage in order to reflect the need for additional ammonia for reducing NOx to 0.035 lb/MMBtu as I recommend as BART. I also conservatively increased the catalyst replacement cost by 1.5 times that of what EPA had considered – in order to account for more frequent cost of catalyst replacement as it deteriorates and is unable to provide the same level of activity to support the 0.035 lb/MMBtu outlet NOx. I also proportionally increased the NOx reduction that can be expected in shifting from 0.05 lb/MMBtu to 0.035 lb/MMBtu. As a result of these changes, the revised cost-effectiveness values I calculated are as follows: $1,808/ton (Unit 1), $1, 879/ton (Unit 2), $1,485/ton (Unit 3) and $1,453/ton (Unit 4). These are marginally higher than the calculated values in Exhibit 1 to EPA's technical support document. And, they are all smaller than the values noted in Table 7 of EPA's preamble for the proposed rule.

In any case, EPA's cost estimates for achieving 0.05 lb/MMBtu are so far below typical cost-effectiveness thresholds used by EPA or by other states (discussed below) that lowering the NOx BART limit to 0.035 lb/MMBtu will still render SCR cost-effective.

Examples of cost-effectiveness threshold values that are much greater than the EPA calculated values include BART determinations recently conducted in Colorado, in which the Colorado Department of Public Health and the Environment (CDPHE) assumed that a cost-effectiveness threshold of $5,000 per ton of emission reduced for NOx is appropriate.

Oregon DEQ has established a threshold of $7,300 based upon the premise that improving visibility in multiple Class I areas warrants a higher cost/ton than where only one Class I area is affected (similar to the present case).[52]

New York uses $5,500 lb/ton and Wisconsin is using $7,000 - $10,000 lb/ton as their BART thresholds.[53]

Recently, EPA published a BART proposal for the Four Corners Power Plant.[54] Speaking directly to the issue of SCR in this BART analysis for NOx control, in this proposal, EPA notes that "...[E]ven if EPA had decided to accept APS's worst case cost estimates of $4,887–$6,170/ton of NOX removed, EPA considers that estimate to be cost effective...."

I note that under similar circumstances, i.e., the consideration of controls as BACT (which, in my opinion is an appropriate basis for evaluating the cost impacts due to BART controls), other agencies have used cost-effectiveness thresholds that are higher.

- In 2001, EPA issued guidance related to presumptive BACT for NOx at refineries being modified to meet EPA's low sulfur gasoline regulation. This guidance used a cost effectiveness threshold of $10,000 per ton of NOx controlled in 2001 dollars.[55]

- The cost effectiveness threshold used for NOx reduction by several California air pollution control districts are substantially more than the threshold in this EPA guidance document, ranging from $9,700 to $24,500 per ton.[56]

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[52] See letter from the National Park Service (NPS) letter to the Utah Department of Environmental Quality dated March 4, 2011, page 5 of the .pdf document.
[53] Ibid.
[54] Fed. Reg., Vol. 75, page 64221, dated October 19, 2010.
[55] Memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects., *available at* http://www.epa.gov/ttnlcaaaltl/memorandalbactguid.pdf. *See also,* Delaware Air Regulation Development Committee Meeting #2 Minutes, April 19, 2006, *available at* http://www.regulations.gov/searchlRegs/home.html#documentDetail?R=09000064807b7424.
[56] San Joaquin Valley Unified Air Pollution Control District, Final Staff Report: Update to BACT Cost Effectiveness Thresholds, May 14,2008 *available at* http://www.valleyair.orgibusindiptolbactlMayo/o202008%20BACT%20cosfO1020effectiveness%20threshold%20update%20staff%2Oreport.pdf, *See also* San Joaquin Valley Unified Air Pollution Control District, Draft BACT Control Technology Policy, March 1, 2010, (proposing to change BACT threshold for NOx form $9,700 to

- A paper presented at the June 2002 Air and Waste Management meeting reported the results of a survey of the threshold for economic feasibility in the BACT determinations and in the LAER determinations separately by state. This survey reported that Connecticut's BACT Determination average cost per ton was $9,000, Arkansas's was $5,108, and Michigan's was $22,000.[57]

These are but examples. In any case, EPA's cost estimates for its BART proposal are so far below any reasonable threshold deeming SCR cost-ineffective that lowering EPA's proposed limit to 0.035 lb/MMBtu on a 30-day rolling average basis would not substantially impact the cost-effectiveness evaluation for SJGS. Hence, the NOx BART for Units 1-4 should be 0.035 lb/MMBtu on a 30-day rolling average basis.

$24,500), *available at* http://71.6.68.101W0rkshops/postings/2010/03-0 1-1 0IDraft%20BACT%2Opolicy%20-%20Mar%2020 10%20).pdf.

[57] "Comparison of the Most Recent *BACT/LAER* Determinations for Combustion Turbines by State Air Pollution Control Agencies, Paper #: 42752, AWMA Meeting June 2002.

Attachment A

RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

311 North Story Place
Alhambra, CA 91801
Phone: 626-382-0001
e-mail (preferred): sahuron@earthlink.net

EXPERIENCE SUMMARY

Dr. Sahu has over twenty one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment; soils and groundwater remediation; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over nineteen years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

Dr. Sahu's experience includes various projects in relation to industrial waste water as well as storm water pollution compliance include obtaining appropriate permits (such as point source NPDES permits) as well development of plans, assessment of remediation technologies, development of monitoring reports, and regulatory interactions.

In addition to consulting, Dr. Sahu has taught and continues to teach numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater and at USC (air pollution) and Cal State Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services.** Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer.** Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

"Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

1. Matters for which Dr. Sahu has have provided depositions and affidavits/expert reports include:

(a) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the US Department of Justice in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (S.D. Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the US Department of Justice in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (S.D. Ill.).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the US Department of Justice in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (M.D.N.C.).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the US Department of Justice in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (S.D. Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert reports and depositions (10/31/2005 and 11/1/2005) on behalf of the US Department of Justice in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (E.D. KY).

(i) Deposition (10/20/2005) on behalf of the US Department of Justice in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (S.D. Ind.).

(j) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(k) Expert report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(l) Expert report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(m) Expert report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(n) Expert report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(o) Expert testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(p) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(q) Expert reports and deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(r) Expert reports and pre-filed testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(s) Expert reports and deposition (October 2007) on behalf of MTD Products Inc., in connection with General Power Products, LLC v MTD Products Inc., 1:06 CVA 0143 (S.D. Ohio, Western Division)

(t) Experts report and deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(u) Expert reports, affidavit, and deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(v) Affidavit/Declaration and Expert Report on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6, under construction in North Carolina.

(w) Dominion Wise County MACT Declaration (August 2008)

(x) Expert Report on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis (June 13, 2008).

(y) Expert Report on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas (February 2009).

(z) Expert Report and deposition on behalf of MTD Products, Inc., in the matter of Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al. (June 2009, July 2009).

(aa) Expert Report on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina (August 2009).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) and Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (October 2009).

(ee) Expert Report, Rebuttal Report (September 2009) and Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ff) Expert report (December 2009), Rebuttal reports (May 2010 and June 2010) and depositions (June 2010) on behalf of the US Department of Justice in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(gg) Prefiled testimony (October 2009) and Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(hh) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(ii) Written Direct Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jj) Expert report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(kk) Declaration (August 2010) on behalf of the US EPA and US Department of Justice in the matter of DTE Energy Company, Detroit, MI (Monroe Unit 2).

(ll) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(mm) Expert Report (August 2010) and Rebuttal Expert Report (September 2010) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(nn) Written Direct Expert Testimony (August 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(oo) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(pp) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of Public Service Company of New Mexico (PNM)'s Mercury Report for the San Juan Generating Station, CIVIL NO. 1:02-CV-0552 BB/ATC (ACE). US District Court for the District of New Mexico.

(qq) Comment Report (October 2010) on the Draft Permit Issued by the Kansas DHE to Sunflower Electric for Holcomb Unit 2. Prepared on behalf of the Sierra Club and Earthjustice.

(rr) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(ss) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(tt) Comment Report (December 2010) on the Pennsylvania Department of Environmental Protection (PADEP)'s Proposal to grant Plan Approval for the Wellington Green Energy Resource Recovery Facility on behalf of the Chesapeake Bay Foundation, Group Against Smog and Pollution (GASP), National Park Conservation Association (NPCA), and the Sierra Club.

(uu) Written Expert Testimony (January 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

2. Occasions where Dr. Sahu has provided oral testimony <u>at trial or in similar proceedings</u> include the following:

(vv) In February, 2002, provided expert witness testimony on emissions data on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(ww) In February 2003, provided expert witness testimony on regulatory framework and emissions calculation methodology issues on behalf of the US Department of Justice in the Ohio Edison NSR Case in the US District Court for the Southern District of Ohio.

(xx) In June 2003, provided expert witness testimony on regulatory framework, emissions calculation methodology, and emissions calculations on behalf of the US Department of Justice in the Illinois Power NSR Case in the US District Court for the Southern District of Illinois.

(yy) In August 2006, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Western Greenbrier) on behalf of the Appalachian Center for the Economy and the Environment in West Virginia.

(zz) In May 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Thompson River Cogeneration) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) before the Montana Board of Environmental Review.

(aaa) In October 2007, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Sevier Power Plant) on behalf of the Sierra Club before the Utah Air Quality Board.

(bbb) In August 2008, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Big Stone Unit II) on behalf of the Sierra Club and Clean Water before the South Dakota Board of Minerals and the Environment.

(ccc) In February 2009, provided expert witness testimony regarding power plant emissions and BACT issues on a permit challenge (Santee Cooper Pee Dee units) on behalf of the Sierra Club and the Southern Environmental Law Center before the South Carolina Board of Health and Environmental Control.

(ddd) In February 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (NRG Limestone Unit 3) on behalf of the Sierra Club and the Environmental Integrity Project before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(eee) In November 2009, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(fff) In February 2010, provided expert witness testimony regarding power plant emissions, BACT issues and MACT issues on a permit challenge (White Stallion Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(ggg) In September 2010 provided oral trial testimony on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (W.D. Pennsylvania).

(hhh) Oral Direct and Rebuttal Expert Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(iii) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(jjj) Oral Testimony (October 2010) regarding mercury and total PM/PM10 emissions and other issues on a remanded permit challenge (Las Brisas Energy Center) on behalf of the Environmental Defense Fund before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(kkk) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(lll) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(mmm) Deposition (December 2010) on behalf of the US Department of Justice in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(nnn) Deposition (February 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(ooo) Oral Expert Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

Attachment B

Data Tables

EXHIBIT 4

NPS/FWS March 31, 2011 letter to Mary Uhl at NMED/AQB and Guy Donaldson at EPA Region 6

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

March 31, 2011

N3615 (2350)

Ms. Mary Uhl
Air Quality Bureau
New Mexico Environment Department
1301 Siler Road, Building B
Santa Fe, New Mexico 87507

Dear Ms. Uhl:

Enclosed are comments that National Park Service (NPS), in consultation with the Fish and Wildlife Service (FWS), submitted to Region 6 of the Environmental Protection Agency (EPA) with respect to the Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology (BART) Determination proposed for San Juan Generating Station (SJGS) on January 5, 2011. We agree with EPA's proposed emissions limit for sulfur dioxide of 0.15 lbs/MMBtu on a 30-day rolling average for SJGS units 1 through 4 to limit interstate transport. We commended EPA for the thorough review of BART controls for nitrogen oxide (NO_x) emissions and agree with EPA that NO_x BART for SJGS is Selective Catalytic Reduction technology.

New Mexico Air Quality Bureau has posted on its website a BART determination for NO_x emissions for SJGS dated February 28, 2011. Since EPA has previously proposed a Federal NO_x BART determination for SJGS, we understand that the federal proposal supersedes the state proposal. We disagree with New Mexico's proposal that Selective Non-Catalytic Reduction technology is sufficient and continue to assert that Selective Catalytic Reduction is BART for SJGS.

We appreciate the opportunity to work closely with the State to make progress toward achieving natural visibility conditions at our National Parks and Wilderness Areas. For further information regarding our comments, please contact Don Shepherd, NPS, at (303) 969-2075 or Tim Allen, FWS, at (303) 914-3802.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service

Enclosure

cc:
Joe Kordzi
Air Planning Section
US EPA Region 6
1445 Ross Avenue
Dallas, Texas 75202-2733

bcc:
Todd Hawes
U.S. EPA OAQPS
Mail Code C539-04
Research Triangle Park, NC 27711

WASO: Julie Thomas McNamee
IMRO: Mike George, John Reber
USFS: Susanna Ehlers (sehlers@fs.fed.us)
USFS: Bret Anderson (baanderson02@fs.fed.us)
FWS-AQB: Tim Allen, Sandra Silva
ARD-DEN: PPPRB, Permit Review Group, Reading and Project File
ARD-DEN: PBrewer:pb:3/25/2011:x2153:NM SIP 3-31-11 Ltr.doc

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO

March 31, 2011

N3615 (2350)

Mr. Guy Donaldson, Chief
Air Planning Section (6PD-L)
Environmental Protection Agency Region 6
1445 Ross Avenue
Suite 1200
Dallas, Texas 75202-2733

EPA Docket No. EPA-R06-OAR-2010-0846

Dear Mr. Donaldson:

This letter responds to the Environmental Protection Agency's (EPA's) Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology (BART) Determination as proposed in the Federal Register on January 5, 2011.

The National Park Service, in consultation with the Fish and Wildlife Service, has conducted a substantive review of EPA's proposed actions for interstate transport and proposed BART determination for the San Juan Generating Station (SJGS). We agree with EPA's proposed emissions limit for sulfur dioxide of 0.15 lbs/MMBtu on a 30-day rolling average for units 1 through 4 to limit interstate transport. We commend EPA for the thorough review of BART controls for nitrogen oxide (NO_x) emissions. We agree with EPA that NO_x BART for SJGS is Selective Catalytic Reduction technology.

We appreciate the opportunity to work closely with EPA to improve visibility conditions at our National Parks and Wilderness Areas. For further information regarding our comments, please contact Don Shepherd at (303) 969-2075.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch

Enclosure

cc:
Joe Kordzi
Air Planning Section
US EPA Region 6
1445 Ross Avenue
Suite 1200
Dallas, Texas 75202-2733

NPS Comments on the Best Available Retrofit Technology (BART) Determination by EPA for Public Service Company of New Mexico's San Juan Generating Station, Units 1-4

March 31, 2011

San Juan Generating Station Source Description:
The San Juan Generating Station (SJGS) consists of four coal-fired electric generating units (EGUs) and associated support facilities. Coal for the units is supplied by the adjacent San Juan Mine and is delivered to the facility by conveyor. SJGS Units 1 and 2 are Foster Wheeler subcritical, dry-bottom, wall-fired boilers that operate in a forced draft mode and have a unit capacity of 360 and 350 MW, respectively. Units 3 and 4 are B&W subcritical, dry-bottom, opposed wall-fired boilers that operate in a forced draft mode, and each have a unit capacity of 544 MW. The presumptive BART limit for Nitrogen Oxide (NOx), which applies to each boiler (> 200 MW) at this large (>750 MW) facility, is 0.23 lb/mmBtu (30-day rolling average) for dry bottom, wall-fired boilers burning sub-bituminous coal.

Consent Decree:
On March 5, 2005,[1] Public Service of New Mexico (PNM) entered into a consent decree (CD) with the Grand Canyon Trust, the Sierra Club, and the New Mexico Environment Department (NMED) to settle alleged violations of the Clean Air Act. The consent decree required PNM to meet a particulate matter (PM) average emission rate of 0.015 lb/mmBtu (measured using EPA Reference Method 5), and a 0.30 lb/mmBtu emission rate for NO_X (daily rolling, thirty day average), for each of Units 1, 2, 3, and 4. As a result, PNM has installed new Low- NO_X burners (LNB) with overfire air (OFA) ports and a neural network (NN) system to reduce NO_X emissions, and pulse jet fabric filters to reduce the PM emissions. In 2010, SJGS ranked #15 in the nation with NO_X emissions of 15,775 tons. Furthermore, the cumulative visibility impact of SJGS at the surrounding Class I areas ranks it among the sources with the highest impacts we have reviewed under the BART program.

NO_X BART Analysis

We shall confine our comments to NO_X, skip the first two steps:
Step 1: Identify All Available Retrofit Technologies
Step 2: Eliminate All Technically Infeasible Control Options
and focus upon the analysis of Selective Catalytic Reduction (SCR) by following the remaining steps in the BART process.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies
PNM contracted with Black & Veatch (B&V) to determine the control effectiveness of each remaining available NO_X and PM control technology for Units 1-4. For the LNB/OFA+SCR option, PNM assumed 0.07 lb/mmBtu (annual average); this represents only a 77% reduction from the current LNB/OFA 0.30 lb/mmBtu emission rate.

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[1] On May 5, 2004, EPA proposed new BART provisions and re-proposed the BART guidelines.

NPS: PNM has **underestimated the ability of SCR to reduce emissions.** For example, B&V assumed that SCR could achieve 0.05 lb/mmBtu (annual average) when evaluating retrofitting of SCR at the Craig power plant in Colorado.[2]

EPA's Clean Air Markets (CAM) data and vendor guarantees[3] show that SCR can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis.[4] We are including 2010 CAM data (electronic Appendix A) that shows that SCR can achieve year-round emissions of 0.05 lb/mmBtu or lower at 26 coal-fired EGUs, eleven of which are dry-bottom, wall-fired units like SJGS. Although SCR may be capable of even lower annual NO_x emissions at SJGS, we will continue to assume 0.05 lb/mmBtu in our analyses to reflect our understanding of vendor guarantees.[5] PNM has not provided any documentation or justification to support the higher values used in its analyses.

We are also presenting information from industry sources that supports our understanding that SCR can achieve 90% reduction[6] and reduce emissions to 0.05 lb/mmBtu or lower[7] on coal-fired boilers. For example, according to the Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants" (published in May 2009), "By proper catalyst selection and system design, NO_X removal efficiencies exceeding 90 percent may be achieved." And, according to the June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO_2 and NO_X Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier, "An excellent example of the significant investment many utilities have made over the past decade is American Electric Power (AEP), one of the largest public utilities in the U.S. with 39,000 MW of installed capacity with 69% of that capacity coal-fired. AEP is under a New Source Review (NSR) consent decree signed in 2007 that requires the utility install air quality control systems to reduce NO_X by 90%..."

Step 4: Perform Impacts Analysis of Remaining Control Technologies—SCR Costs

One metric for estimating the Total Capital Investment (TCI) is the SCR cost expressed in $/kW. The TCI costs estimated by PNM (in 2010 $) are shown below:

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[2] Exhibit 16 - Craig Stations 1, 2, and 3 November 2010 Black & Veatch Report, Tables 2-1, 2-1, 4-6,4-8, 7-7, 7-8, "Selective Catalytic Reduction System"

[3] Minnesota Power has stated in its Taconite Harbor BART analysis that "The use of an SCR is expected to achieve a NO_X emission rate of 0.05 lb/mmBtu based on recent emission guarantees offered by SCR system suppliers."

[4] For example, Salt River Project is using 0.05 lb/mmBtu as the design basis for its revised analysis of adding SCR at its Navajo Generating Station.

[5] A NO_X limit of 0.06 lb/mmBtu is appropriate for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates.

[6] For example, please see the May 2009 Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants" and the June 13, 2009, "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

[7] 12/15/09 presentation by Rich Abram of Babcock Power to the Minnesota Pollution Control Agency. Not only does Babcock Power say that SCR can achieve 0.05 lb/mmBtu, they are currently designing systems to go as low as 0.02 lb/mmBtu.

Unit	SJGS #1	SJGS #2	SJGS #3	SJGS #4
Capital Cost[8] (TCI)	$184,143,000	$ 198,790,000	$ 248,416,000	$ 230,089,000
Capital Cost ($/kW)	$ 512	$ 568	$ 457	$ 423

The B&V 10/22/10 Cost Analysis escalated the original May 2007 costs to September 2010 using data for certain materials and equipment from the U.S. Bureau of Labor Statistics, confirmed by B&V's corporate escalation tool. While escalation to current dollars is a reasonable adjustment, it does not affect the outcome of a cost effectiveness analysis because the cost effectiveness of other analyses used to establish the acceptable cost range should also be adjusted for escalation.

B&V's calculations do not consider the weakening of labor markets that has occurred since they set up their spreadsheets in 2007. According to B&V, in the pre-2004 period, its estimating department found that construction indirects were typically 50% to 60% of installation labor costs. In the post-2005 period, they reported construction indirects rose to a range of 90% to 120% of installation labor costs due to tightening in labor markets. However, in the 2010-revised cost estimate, Black & Veatch did not adjust the construction indirects to reflect the loosening of the labor market. The tightening of the labor markets has now reversed, skilled labor is underutilized, and per diem is not being paid at all, or only paid for a portion of the labor force.

"Real-World" SCR Capital Costs

Real-world, utility industry-generated evidence that PNM has overestimated its SCR costs can be found in a June 2009 article in "Power" magazine:[9] "One more current data set is the historic capital costs reported by AEP averaged over several years and dozens of completed projects. For example, AEP reports that their historic average capital costs for SCR systems are $162/kW for 85% to 93% NO_X removal..."

"...historical data finds the installed cost of an SCR system of the 700MW-class as approximately $125/kW over 22 units with a maximum reported cost of $221/kW in 2004 dollars. This data was reported prior to the dramatic increase in commodity prices of 14% per year average experienced from 2004 to 2006 (from the FGD survey results). Applying those annual increases to the 2004 estimates for three years (from the date of the survey to the end of 2007) produces an average SCR system installed cost of $185/kW..." (or $184/kW in 2009 $).

"Overall, costs were reported to be in the $100 to $200/kW range for the majority of the systems, with only three reported installations exceeding $200/kW."

[8] Table 1 of the PNM 2.11.11 submittal.

[9] June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, expressed in dollars per kilowatt. These actual costs are lower than estimated by PNM for SJGS.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $211/kW, converted to 2009 dollars.[10] Costs are escalated through using the 2009 CEPCI (because the final 2010 CEPCI is not yet available).

The second survey of 40 installations at 24 stations reported a cost range of $75 to $240/kW, converted to 2009 dollars.[11]

The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, or 39% of installed SCR systems in the U.S. This study reported a cost range of $118/kW to $261/kW, converted to 2007 dollars.[12]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $178/kW to $201/kW, converted to 2009 dollars.[13]

A fifth summary study, focused on recent applications that become operational in 2006 or were scheduled to start up in 2007 or 2008, reported costs in excess of $200/kW on a routine basis, with the highest application slated for startup in 2009 at $300/kW.[14]

Other recent estimates suggest that the SJGS SCR capital costs may be overestimated. Wisconsin Electric estimated the cost to retrofit SCR on Oak Creek Units 5-8 to be $175/kW[15] for a cold-side SCR. This cost was certified in July 2008 for construction by the Wisconsin Public Services Commission.[16] Wisconsin Power and Light estimated the cost to retrofit SCR on the 430-MW

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[10] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Ex. 2. The reported range of $80 to $160/kW was converted to 2009 dollars ($106 - $211/kW) using the ratio of CEPCI in 2009 to 2002: 521.9/395.6.

[11] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004, Ex. 4. The reported range of $56/kW - $185/kW was converted to 2009 dollars ($75 - $240/kw) using the ratio of CEPCI for 2009 to 1999 (521.9/.390.6) for lower end of the range and 2009 to 2003 (521.9/401.7) for upper end of range, based on Figure 3.

[12] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2009 dollars ($117 - $260/kW) using the ratio of CEPCI for 2009 to 2004: 521.9/444.2. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

[13] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Ex. 6. The reported range of $160 - $180/kW) was converted to 2009 dollars ($178 - $201/kW) using the ratio of CEPCI for 2009 to 2005 (521.9/468.2).

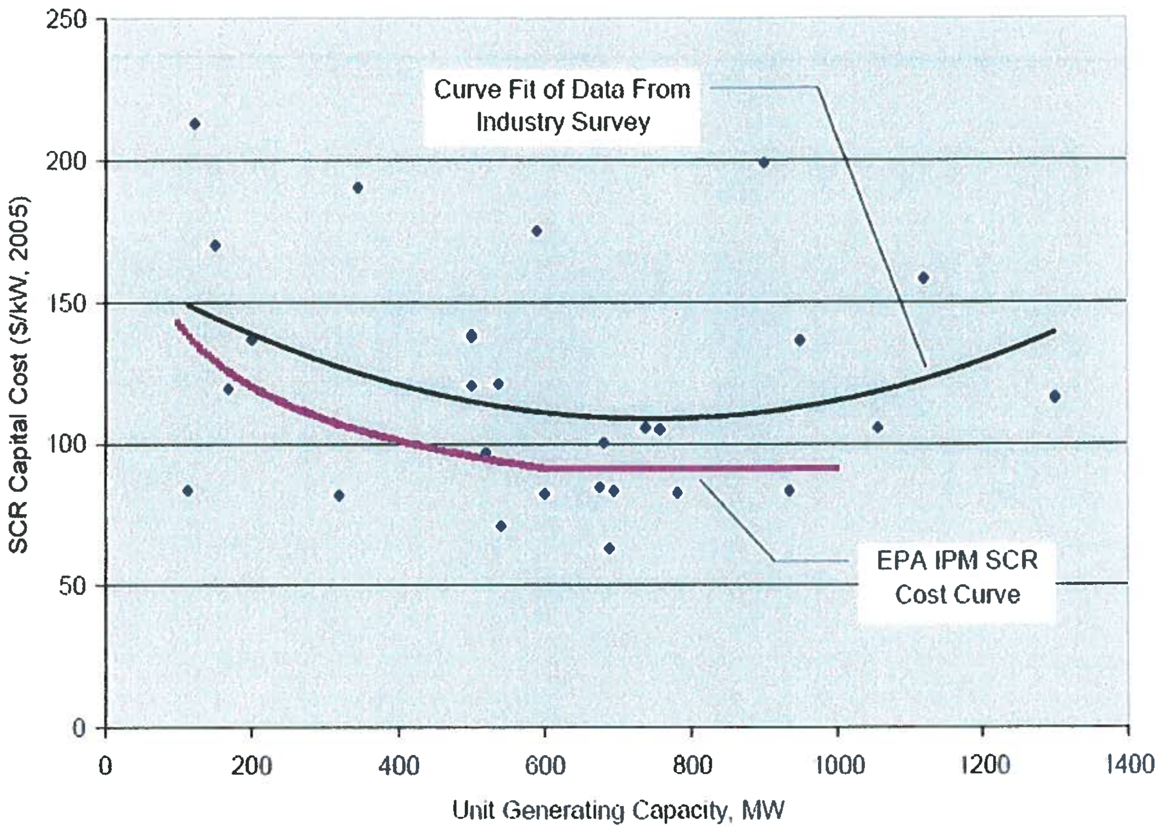
[14] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Ex. 1).

[15] Wisconsin Electric Power Company's Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Appendix C, Emission Reduction Study, Volume 1, Addendum August 20, 2007. Unit cost = ($190,500,000/1,135,000 kW) (521.9/499.6) = $175 kW.

[16] Certificate and Order, Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Case 6630-CE-299, July 10, 2008. Available here: http://www.we-energies.com/home/OCPP_approvalPSCWOrder.pdf.

Edgewater Unit 5 to be $324/kW in January 2008.[17] Similarly, American Electric Power (AEP) estimated that the average capital cost to install SCRs to remove 85-93% of the NOx from many of its units was $162/kW.[18]

EPA's Region 8 Office has compiled a graphic presentation of SCR capital costs—please see Appendix B for "SCR References"



The EPA data confirm that SCR capital costs typically range from $73 – $243/kW. In comparison, PNM's cost estimates for SJGS appear to be overestimated.

A graphic illustration of a "real-world" retrofit was presented by Burns & McDonnell at the 2010 Power Plant MegaSymposium and is provided in Appendix B in the "Boswell retrofit" files. Despite the limited space and other obstacles, the SCR installation cost $224/kW.[19] It should also be noted that the Boswell #3 retrofit was designed to meet 0.05 lb/mmBtu annual average and a

[17] Wisconsin Power & Light Co., Certificate of Authority Application, Edgewater Generating Station Unit 5 NOx Reduction Project, Project Description and Justification, November 2008, PSC Ref#: 105618, p. 11. The unit cost was calculated from the total project cost minus escalation divided by gross generating capacity or: ($153,944,000 - $14,695,000)/430 MW = $323.8/kW.
[18] AEP, 2008 Fact Book, 43rd Financial Conference, Phoenix, AZ, pdf 103. Available here: http://www.aep.com/investors/present/documents/2008EEI-Fact-Book.pdf.
[19] Minnesota Power's Environmental Improvement Plan submitted to the MN PUC 10/27/06, Docket #E015/M-06-1501. LNB+OFA+SCR TCI = $77 million in 2006 $ on 375 (gross) MW Unit #3 = ($77,000,000)/ (375,000) (521.9/499.6) = $224/kW.

0.07 lb/mmBtu 30-day rolling average. Burns & McDonnell reported that performance tests showed that, "Average NOx emissions at the outlet of the SCR reactor were 0.029 lb/mmBtu, which is below the design emission rate for the SCR system (0.05 lb/mmBtu)."

The overall range for these industry studies is $50/kW to $400/kW.[20] The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost $383/kW,[21] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[22] cost $236/kW in 2009 dollars.[23] PNM has presented no valid information to show why its cost estimates should exceed all available industry data.

PNM's SCR capital cost estimation methods are flawed.

<u>PNM has improperly rejected use of the OAQPS Control Cost Manual (Cost Manual) in favor of methods not allowed by EPA.</u>

The SCR cost estimates submitted by PNM are severely lacking in the types of specific information needed to give them credibility. According to B&V, PNM's consultant, "Capital cost estimates were developed for retrofit control technologies identified as technically feasible for the SJGS units. The capital cost estimates were based on the Coal Utility Environmental Cost (CUECost) estimates, cost data supplied by equipment vendors (budget estimates), and estimates from previous in-house design/build projects."

Both OAQPS and EPA Region 8 have advised against the use of the CUECost model, which was relied upon by B&V. Instead, the BART Guidelines recommend use of the Cost Manual:

> The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

As detailed in EPA's analysis of the B&V cost estimates and discussed later, the "vendor quotations" cited by B&V as the basis for its SCR cost estimates for SJGS were taken from a project in Florida that is different from SJGS, thus giving the wrong idea or impression. The "estimates from previous in-house design/build projects" cited by B&V, as noted below, are simply factored estimates based upon Purchased Equipment Cost estimates.

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[20] Exhibit 19 - J.E. Cichanowicz Overview of Information on Project Control Technology Costs – October 15, 2010

[21] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost: ($325,000,000/1,120,000 kW) (521.9/395.6) = $383/kW.
http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

[22] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[23] McIlvaine, NOX Market Update, August 2004, Ex. 9. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at $179/kW. Assuming 2002 dollars, this escalates to ($179/kW) (521.9/395.6) = $236/kW.
http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

EPA's belief that the Control Cost Manual should be preferred over CUECost for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to the North Dakota Department of Health:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

Larry Sorrels, an economist at EPA's Office of Air Quality Planning and Standards (OAQPS) wrote the following to Aaron Worstell of EPA Region 8 on September 8, 2010:

> the way that CUECost estimates total capital cost and O&M cost is different from the Control Cost Manual. In particular, the total capital cost estimate from CUECost is the same as the total capital requirement (TCR), an estimate that is part of the levelized cost methodology devised by EPRI. A TCR estimate includes Allowance for Funds Used During Construction (AFUDC), an estimate that is not included in the total capital cost according to the Control Cost Manual method. Also, O&M costs are calculated differently, with fixed and variable components being included in the O&M costs, a distinction at odds with the Cost Manual method.

We note that, in New Mexico Environment Department's (NMED) December 21, 2007, letter to PNM, the NMED requested that the cost estimate for SCR be performed using the OAQPS Cost Manual. In its March 29, 2008, response, "Discussion of OAQPS Cost Manual Method for AQCS Estimation," PNM states that "there are two main reasons that the Cost Manual was not used. First, the price of SCR systems (and other AQC retrofits) has increased dramatically in the past 10 years, and especially since 2005. Second, the Cost Manual does not include many categories of equipment and construction that are required for the complete installation of an SCR system consistent with common industry practices." Application of an escalation factor (such as the CEPCI) to the Direct Capital Cost remedies the first problem, and we disagree that the Cost Manual approach omits significant costs.

PNM discussed the need to escalate costs estimated using the Cost Manual, and we agree. We have been advised by OAQPS[24] to use the Chemical Engineering Plant Cost Index (CEPCI) which has risen from 389.5 in 1998 (the Cost Manual SCR reference date) to 521.9 in 2009,[25] a factor of 1.34. It appears that PNM has escalated costs from 1998 to 2007 by a factor of 1.66.

We are not sure how PNM concluded that "the Cost Manual is geared more towards developing costs for new units than retrofitting controls on existing units," because the Cost Manual contains an adjustment for retrofit situations.

In section 2.16, "Construction Indirects", PNM discusses the "cost items included in construction indirects include construction equipment, construction contractor overhead and profit, tools, site

[24] July 21, 2010, e-mail from Larry Sorrels of EPA OAQPS to Don Shepherd: "On cost indexes, I prefer the CEPCI for escalating/deescalating costs for chemical plant and utility processes since this index specifically covers cost items that's pertinent to pollution control equipment (materials, construction labor, structural support, engineering & supervision, etc.).The Marshall & Swift cost index is useful for industry-level cost estimation, but is not as accurate at a disaggregated level when compared to the CEPCI. Thus, I recommend use of the CEPCI as a cost index where possible."

[25] We suggest that 2009 be used until the 2010 CEPCI is available.

trailers and utilities, construction supervision, and construction contractor administrative support." PNM then states that, "The Cost Manual does not address these costs in any way yet these are real costs that will be incurred in order to support the direct cost of installing the SCR system." We believe that the Cost Manual does, indeed, address these costs as discussed below.

Cost Manual Chapter 2. Cost Estimation: Concepts and Methodology

2.3.1 Elements of Total Capital Investment
Indirect installation costs include such costs as engineering costs; construction and field expenses (i.e., costs for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.

Cost Manual Chapter 2, Selective Catalytic Reduction

2.4.1 Total Capital Investment, Indirect Capital Costs
Indirect installation costs are those associated with installing and erecting the control system equipment but do not contribute directly to the physical capital of the installation. This generally includes general facilities and engineering costs such as construction and contractor fees, preproduction costs such as startup and testing, inventory capital and any process and project contingency costs.

In his book Estimating Costs of Air Pollution Control, William Vatavuk (who was primarily responsible for the Cost Manual while at EPA) provides this insight regarding Indirect Costs:

> "The indirect (soft) installation costs comprise engineering costs, construction and field expenses (e.g., rental of trailers and like equipment), contractor fees (for firms involved in the project), startup and performance tests (to get the control system running and to verify that it meets the vendor's guarantees), and contingencies."

PNM has included costs not allowed by EPA, and overestimated other costs.

PNM is including a separate $22 million cost for Owner's Costs: "Owner's costs include items such as staff for site coordination during construction, equipment receiving, contract management, interface with regulatory agencies, and owner engineering costs." In its May 10, 2010, formal comments to the North Dakota Department of Health, EPA rejected the inclusion of "Owner Costs" in the analysis of adding SCR to the Milton R. Young (MRYS) power plant:

> As noted above, the total direct capital costs used by B&McD appears to be overestimated. A large portion of this discrepancy comes from the "other" costs added by B&McD (Table 2) that are not included in the Control Cost Manual. These appear to be strictly contingencies and accounting items which would not be at all unique to MYRS and, therefore, are not justified in the analysis. These accounting items are unauthorized under the Control Cost Manual, create an unlevel playing field for comparison with other BACT analyses and alone account for an increase in capital costs from the Control Cost Manual by a factor of 1.6.

PNM has also included a $78 million cost for Allowance for Funds During Construction (AFUDC) for SCR at SJGS that may not be allowable because if the AFUDC cost is not "already included in the base case as per a utility commission decision." Mr. Sorrels also provided[26] insight on the AFUDC:

> I agree with including AFUDC in a capital cost estimate if this is already included in the base case as per a utility commission decision. Otherwise, I do not agree with its inclusion.

The estimates provided by PNM are its consultant's rough estimates based upon developing a Total Purchased Equipment Cost (PEC) or Direct Capital Cost (DCC) and applying its standardized estimation factors to the PEC/DCC. As a result, PNM has generated capital cost estimates that exceed real-world industry data and contain items that are inflated and/or not allowed by EPA.

The \$423 - \$568/kW (estimated by PNM in 2010 \$) TCI provided by PNM is indicative of the overestimates throughout the analysis presented by PNM. These deviations from standard practice project the cost to control NOx using SCR at SJGS to be higher than at other similar sources. However, these apparently higher costs appear to be due to the PNM costing method, not to any unique circumstances at the units that may make the retrofit of SCR unusually costly.

The Guidelines suggest that documentation be provided for "any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits." PNM has provided no documentation regarding unique circumstances related to the BART determinations. All of PNM's TCI estimates, when reduced to \$/kW, exceed the highest actual costs reported by the industry.

Some additional examples of the PNM capital cost overestimates are taken from the B&V cost analysis and are presented below.

The B&V estimates are higher than other recent estimates, including its own. The cost for most of these items was scaled from the Saint Johns River Power Park (SJRPP) project that B&V had completed the year before they did the initial SJGS cost estimate. Costs for some items were also scaled from other unidentified projects. The unit capital cost for the SJRPP SCR that B&V designed and used to scale costs to the SJGS SCR is \$187/kW in 2010 dollars. This is a factor of two to three less than B&V estimated for SJGS by extrapolating from SJRPP. As explained elsewhere, the SJRPP SCR would be more costly than an SCR at SJGS as SJRPP burns a very challenging coke/coal blend.

The SCR retrofit for SJRPP involved significant challenges due to the range of fuels and direct bunkering operations for purposes of blending fuels, which is not practiced at SJGS. The SJRPP fuels include a blend of 30% petroleum coke and 70% coal, with coke fired for up to 6,000 hours. The coals included a low calcium eastern domestic coal and a high-silica (erosive) Colombian coal. These three fuels coupled with direct-bunkering resulted in designs that do not extrapolate to SJGS and, in fact, overestimate SJGS costs when extrapolated from SJRPP. The six-tenth rule that B&V used in these extrapolations only applies when the underlying design is identical.

[26] 7/21/10 e-mail to Don Shepherd

Ductwork and ammonia injection grid costs for SJGS are overestimated. Petroleum coke firing results in higher flue gas temperatures than coal firing. This required material selection based on a design temperature of 824 °F and the use of more expensive materials of construction for SJRPP: ASTM A588 for ductwork and ASTM A335 P11 for the ammonia injection grid. The flue gas temperature for the SJGS units ranges from 707 °F at Unit 1 to 720 °F at Units 3 and 4.[17] As discussed below, more expensive ductwork materials were used for the SJRPP, based on higher anticipated flue gas temperatures than are present at the SJGS. Thus cheaper materials could be used for the ammonia injection grid and the ductwork.

Petroleum coke firing results in high levels of unburned carbon, which increases the risk of fires in the ductwork. To avoid fly ash deposition on the ductwork floor, the SJRPP ductwork was designed with a high average flue gas velocity, which increases the cost of the ductwork, reactor housing, and catalyst compared to the cost of comparables at SJGS. As ductwork fires are not an issue at SJGS, an SCR could be designed with a lower duct velocity, thus decreasing the cost of most components of the SCR.

Petroleum coke also contains high levels of sulfur, up to 6.94%, compared to 0.77% sulfur in the coal burned at SJGS. The high fuel sulfur at SJRPP results in corrosive flue gases that form sulfuric acid mist and ammonium bisulfate in the pollution control train, thus requiring more expensive materials of construction.

The B&V BART cost for the reactor box, breeching and ductwork was based on a preliminary quote of $5,613,000 per unit for SJRPP, which was adjusted to account for differences in the size of the SJGS units. The final contract price was $4,877,223 per unit. Thus, the B&V cost analysis was adjusted to use the final cost. The cost was adjusted to 2007 dollars using an escalation rate of 1.03. This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. Further, more expensive materials of construction were used for SJRPP as maximum flue gas temperatures were higher (>750 °F) than expected at SJGS (<700 °F).

The expansion joint cost was scaled from the total cost for both SJRPP units ($360,430) instead of one unit, using the ratio of volumetric gas flow rate in acfm and adjusted to 2007, using an escalation rate of 1.03. This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. Further, the vendor quoted price includes freight, which is double counted elsewhere in the B&V cost analysis. Finally, the joints are designed for an operating temperature of 800 °F with excursions to 900 °F. This is far higher than expected at SJGS, which could use less expensive materials.

The sonic horn cost was estimated from a preliminary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03 and further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. However, the final contract award was lower. Further, the final contract award included freight to the site, which is double counted elsewhere in the B&V cost spreadsheet.

The elevator cost was estimated from a preliminary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03 and further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. However, the final contract award was lower. Further, the final contract award includes installation, which is broken out separately on the bid form, as well as freight and taxes.

Installation, freight, and taxes are calculated elsewhere in the B&V cost spreadsheet and thus are double-counted.

The structural steel cost was estimated from a budgetary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03, and a "complexity factor." This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. The complexity factor is a contingency for site congestion that has been double counted in a contingency figured as 20% total direct costs, as discussed elsewhere. Further, inspection of Google Earth images of SJGS and SJRPP suggests that SJGS is not more congested than SJRPP. Finally, the B&V structural steel cost includes freight to the jobsite, which is included elsewhere. Even with these adjustments, structural steel costs are overestimated, as the contract award amount used to make these extrapolations included "all associated engineering and design costs, procurement, fabrication, overtime, overhead, profit mark-up and shipping to the jobsite." Further, the structural steel was to be delivered painted; these costs are double-counted elsewhere.

The SCR bypass cost was estimated from a budgetary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03, and a "complexity factor." This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. This results in a cost of $10 million per unit for an SCR bypass to route flue gas around the catalyst during startup. This is claimed to be required to prevent catalyst fouling when firing oil during startup. However, fouling would only occur if the oil is not burned and thus coats the catalyst. This could only occur due to poor combustion. Oil is very efficiently burned in modern Low-NO_x Burners with oil igniters, such as those on the SJGS units, which were installed between 2007 and 2010. If these burners are properly maintained and operated, fouling during startup will not occur.

Catalyst can be designed to avoid oil startup issues. The Mirant Unit 1 & 2 SCR system at the Morgantown Station is designed to remove 92.5% of the NO_x, to an outlet of 0.045 lb/mmBtu, for year round operation with no SCR bypass during startup when the plant fired fuel oil and for No. 6 oil during cofiring. Similarly, Duke Energy's Belews Creek Steam Station, for example, has operated two 1200-MW bituminous coal- fired boilers with SCR since 2004, with oil startup and no catalyst bypass. Further, there are oil-fired boilers and turbines equipped with SCR that operate without bypasses.

The NO_x Monitoring cost was estimated from a preliminary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03 and further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. However, the final contract award was lower. The final contract award included freight to the site, on-site training for each of two units, and a 3-year maintenance contract. Freight and maintenance are double-counted as they are included elsewhere. Further, only a single training session is required for all four SJGS units, not a separate training session for each unit, as estimated by B&V.

In the October 22, 2010, revision to its cost analysis, B&V added a new cost item, "auxiliary electric system requirements," amounting to $6,400,000 for each of Units 1 and 2 and $8,350,000 for each of Units 3 and 4. These additions are based on "minimum" load changes due to the SCR totaling 26,254 kW. These increased loads are met by replacing existing fans with larger fans and include flow margins of 15% to 20% and pressure margins of 35% to 45%.

The auxiliary power upgrade is required due to the cumulative effect of the Consent Decree projects and the SCR and benefits the entire fan auxiliary system. The SCR project was initially evaluated at the same time that the Consent Decree projects were being designed. B&V states: "In the initial 2007 estimate, PNM expected the existing auxiliary power to be sufficient. However, now that the consent decree AQC equipment has been installed, B&V has determined that the current auxiliary power system is not sufficient to power the additional loads that would result from adding SCR and associated equipment." Further, the auxiliary power upgrades cumulatively serve the increase in auxiliary power. The modifications, for example, include new transformers, switchgear, and motor control centers that will serve the entire fan auxiliary loads of both the Consent Decree projects and the SCR. Thus, these costs should be prorated, rather than partitioned to the last project built.

The instrumentation and control system cost was estimated from a preliminary quote for SJRPP, adjusted to 2007 using an escalation rate of 1.03 and further escalated to 2010 dollars per the Black & Veatch 10/22/10 cost analysis. However, the final contract awards were higher. They consist of the sum of bids from two separate contractors. In each case, the quotes include freight to the site and installation, both of which are double counted elsewhere.

The 2007 cost estimate included $1,071,000 to modify each of the air preheaters at Units 1 and 2 and $8,685,000 to modify each of the air preheaters at Units 3 and 4. In response to an EPA comment, B&V modified the Units 3 and 4 estimate to eliminate double counting, revising the cost for Units 3 and 4 to $5,090,000 each. These figures were further escalated to 2010 dollars in the B&V 10/22/10 cost analysis. These estimates were variously claimed to be based on "the experience of a confidential client" and a "quote for SJGS" and "scaled from another project." B&V declined to share the basis for these costs with EPA.

The air preheater modifications are not required for a properly designed SCR on a boiler that burns low sulfur coal. B&V asserts the upgrades are required to make the air preheaters resistant to ammonium bisulfate corrosion and plugging. Air preheater modifications are required for units that burn high sulfur coal. However, SJGS burns a low sulfur coal containing only 0.77% sulfur. These lower sulfur coals generate very little sulfur trioxide and thus little ammonium bisulfate corrosion and plugging. Air heater plugging is not an issue for these coals if the SCR is designed with a low SO_2 to SO_3 catalyst and an ammonia slip of 2 ppm. These are both proposed for the SJGS SCR. Thus, air preheater modifications are not required for the SJGS SCR. (See discussion of this issue by Sargent & Lundy for a similar facility burning a similar coal in a BART analysis for the Navajo Generating Station.)

The revised B&V costs include $14.3 million at each of Units 1 and 2 and $18.7 million at each of Units 3 and 4 for balanced draft conversions. These figures were further escalated to 2010 dollars in the Black & Veatch 10/22/10 cost analysis. The majority of these costs, 70%+, is due to stiffening of the boiler, air heater, electrostatic precipitator, and fabric filter to comply with code. The balance of the costs are for induced draft fans to support the increased draft from the SCR and new motors for existing forced draft fans. Although increased draft is needed to support an SCR, which would be delivered by the induced draft fans, a balanced draft conversion with the proposed stiffening is not part of an SCR project. As balanced draft conversion is not required for an SCR, under this interpretation, stiffening would not be required.

The B&V cost analyses assume a 12-week outage would be required to complete the balanced draft conversion. The SCR would be installed during the routine seven-week outage. The remaining five weeks is required for the stiffening. This charge is not allowed by the Cost Manual. Further, it is unwarranted as the required stiffening work can be completed over multiple routine outages. With planning, no lost generation would be incurred.

The contingencies included in the B&V cost estimates are double-counted. There are three separate contingencies imbedded in the analysis. First, the cost of structural steel and the SCR bypass were increased by a factor of 1.2 at Units 1 and 4 and by a factor of 1.5 at Units 2 and 3 to address the "significantly more challenging site at SJGS compared to SJRPP." Second, a separate contingency of $2,000,000 was included for each unit for "site unknowns, such as underground utilities" and $500,000 for each unit for "general site building requirements". Third, a contingency of 20% of total direct costs (thus building contingencies on top of contingencies) was included for each unit under indirect costs. This latter contingency was based on the CUECost model, which has not been approved for BART cost analyses. The sum of these contingencies amounts to approximately $18 million for Unit 1, $22 million for Unit 2, $27 million for Unit 3, and $23 million for Unit 4, or about two thirds of the purchased equipment cost. The Cost Manual stipulates a 5% process contingency for indirect installation costs, figured as 5% of total direct costs, and a 15% project contingency, figured as 15% of total direct and total indirect installation costs.

The factors used for SJGS are unsupported in the record, even though New Mexico specifically requested support. The factors are demonstrably high. An SCR is a metal frame stuffed with blocks of catalyst. It has no moving parts. Painting, for example, is minimal as most items arrive at the site primed; structural steel arrives at the site painted. In fact, Black & Veatch zeroed out both painting and insulation in its calculation of construction indirects, but failed to carry this over to direct installation costs. Foundation and supports, estimated as 30% of purchased equipment cost, are two to three times higher than upper bound costs reported by others for similar sized units ($8/MW compared with $18/MW to $29/MW for SJGS).

NPS' Application of the EPA Control Cost Manual

Based upon industry and EPA estimates, we assumed a TCI of $200/kW for the two smaller EGUs and $180/kW for the two larger EGUs.

Annual SCR Costs and Cost-effectiveness expressed in $/ton of NO_X Removed.

The Direct Annual Cost (DAC) component of the process is also important because it represents a significant portion of the Total Annual Cost. The methods presented by the Cost Manual for estimating DAC appear to be straightforward and should accurately represent annual costs with no need for adjustment.

<u>PNM has overestimated annual operating costs.</u>

While PNM presented an extensive comparison of its method for estimating capital costs versus that of the Cost Manual, we were unable to find a similar discussion regarding annual costs. The only information we could find regarding annual costs (which are critical to the cost-benefit analyses), was contained in Appendix C of PNM's June 6, 2007, BART analysis,[27] and it has not been updated to reflect PNM's subsequent higher estimates of TCI. In addition to the higher-than-recommended ratios used by PNM to estimate its TCI, the estimates generated by PNM for its annual operating costs are also higher than corresponding estimates generated by the Cost Manual.[28]

- Operating labor was estimated at $125,000/yr for each unit, based on one full time equivalent (FTE). However, the Cost Manual explains that the SCR reactor is a stationary device with no moving parts and uses only a few pieces of rotating equipment (e.g., pumps, motors). Thus, existing plant staff can operate the SCR from the existing control room. The Cost Manual explains: "In general, operation of an SCR system does not require any additional operating or supervisory labor." Maintenance labor and materials were estimated by B&V as 3% of the total direct costs. However, the Cost Manual reports that maintenance labor and material should be estimated as 1.5% of total capital investment.
- PNM's $700/ton reagent cost is much higher than any we have seen elsewhere.
- B&V assumed a total auxiliary power demand of 16,297 kW for the four units, which amounts to 0.9% of the total gross generating capacity of the station. An SCR typically uses about 0.3% of a plant's electric output, which would be about 5,400 kW or three times less than assumed in the cost analysis. Second, the unit cost of electricity used by B&V, $0.06095/kWh, is higher than the default cost used in cost effectiveness analyses, $0.05/kWh. Auxiliary power is the power required to run the plant, or power not sold. Cost effectiveness analyses are based on the cost to the owner to generate electricity, or the busbar cost, not market retail rates. The B&V estimate is based on the average forecasted cost of replacement power for 2007 to 2012. Other recent BART analyses for similar facilities have used auxiliary power costs that range from $0.03/kWh to $0.05/kWh.
- PNM has assumed a two-year catalyst life instead of the typical three years; this inflated the Annual Catalyst Costs. Catalyst replacement cost did not consider catalyst regeneration, which has become an alternative to purchasing new catalyst since the Cost Manual was last updated. The cost of purchasing new catalyst was assumed to be $6,500/m^3, while the cost to regenerate is about 60% of this price. Setting aside regeneration, the catalyst cost used by Black & Veatch, $6,500/m^3, is higher than the cost recently quoted by Hitachi for a nearly identical coal, $5,500/m^3 to $6,000/m^3.The catalyst volume was scaled from another Black & Veatch project, Harding Street Unit 7. The scaling took into account the difference in flow rates but not the differences in NO_x reduction. For the 0.07-lb/MmBtu cases, SJGS catalyst volume should be based on reducing NO_x from 0.3 lb/MmBtu to 0.07 lb/MmBtu or by 0.23 lb/MmBtu. For the 0.05-lb/MmBtu cases, catalyst volume should be based on reducing NO_x from 0.3 lb/MmBtu to 0.05 lb/MmBtu or by 0.25 lb/MmBtu. The Harding catalyst volume was based on reducing NO_x from 0.34 lb/MmBtu to 0.044 lb/MmBtu or by 0.3 lb/MmBtu. When the difference in NO_x reduction is factored in, catalyst volume, and hence replacement cost,

[27] PNM's March 2008 "Discussion of OAQPS Cost Manual Method for AQCS Estimation," Appendix B "Details of Cost Calculation Using OAQPS Cost Manual" was presented in response to NMED's request for an analysis following the Cost manual.

[28] We do not understand why the Indirect Annual Costs calculated by PNM remained constant from 2008 to 2010 in spite of the increased TCI estimated by PNM.

drop by about 15% for the 0.07-lb/MmBtu cases and by about 10% for the 0.05-lb/MmBtu cases.

- PNM used a 7.41% interest rate instead of the 7% rate recommended by EPA. Combined with the inflated TCI, this further inflated the Indirect Annual Costs.
- PNM's estimates are based upon achieving 0.07 lb/mmBtu, which represents 77% NO_x reduction from the Consent Decree limit of 0.30 lb/mmBtu to be achieved by combustion controls. This lower removal estimate inflated PNM's cost/ton estimates.

These issues result in PNM's Total Annual Cost and Cost/ton estimates that go well beyond what is usual, regular, or customary.

An excellent example of a SCR retrofit cost analysis was prepared for the Navajo Generating Station (NGS) and submitted to EPA Region 9.[29] The NGS analysis contains the type of vendor estimates and detailed engineering analyses that are recommended by the BART Guidelines and that are necessary to arrive at a reasonable and informed estimate of site-specific costs. In the absence of such a comprehensive analysis, the BART Guidelines recommend use of the EPA Control Cost Manual.

<u>NPS estimate of annual operating costs.</u>

We also performed annual cost estimates using the Cost Manual for SJGS and used catalyst[30] and ammonia costs obtained from vendor quotes and from Salt River Project's BART analysis for the Navajo Generating Station because they were better documented and appeared more realistic. Using our estimates of Total Capital Investment coupled with a direct application of the Cost Manual methods to estimate annual costs, we estimated the costs shown in the table below:

Annual Costs* & Benefits	Unit #1		Unit #2		Unit #3		Unit #4	
	NPS	PNM	NPS	PNM	NPS	PNM	NPS	PNM
Annual Maintenance Cost =	$ 1,080,000	$ 2,369,000	$ 1,050,000	$ 2,532,000	$ 1,468,800	$ 3,166,000	$ 1,468,800	$ 2,961,000
Annual Reagent Cost =	$ 638,555	$ 911,000	$ 630,810	$ 906,000	$ 966,343	$ 1,415,000	$ 997,237	$ 1,388,000
Annual Electricity Cost =	$ 575,558	$ 1,496,000	$ 568,577	$ 1,492,000	$ 1,005,010	$ 2,194,000	$ 898,854	$ 2,215,000
Annual Catalyst Cost =	$ 385,341	$ 426,000	$ 382,027	$ 426,000	$ 458,338	$ 538,000	$ 610,813	$ 541,000
Direct Annual Cost =	$ 2,679,454	$ 5,252,000	$ 2,631,414	$ 5,406,000	$ 3,898,491	$ 7,363,000	$ 3,975,704	$ 7,155,000
Indirect Annual Cost =	$ 6,796,291	$ 15,194,802	$ 6,607,505	$ 15,194,802	$ 9,242,955	$ 15,194,802	$ 9,242,955	$ 15,194,802
Total Annual Cost =	$ 9,475,745	$ 20,525,000	$ 9,238,919	$ 21,891,000	$ 13,141,446	$ 29,870,802	$ 13,218,659	$ 26,592,000
NOx Removed =	3,459	3,174	3,417	3,158	5,235	4,931	5,402	4,837
SCR Cost effectiveness =	$ 2,739	$ 6,466	$ 2,704	$ 6,932	$ 2,510	$ 5,752	$ 2,447	$ 5,497

***All costs are in 2010 $ except NPS' "Annual Maintenance Cost" and "Indirect Annual Costs" which are in 2009 $ (which also partially affect the "Total Annual Cost").**

In addition to the PNM overestimates noted above, some additional differences highlighted in the table are:

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29 http://en3pro.com/2011/01/30/cost_estimate_report/

30 2010 vendor quotes for low-oxidation catalyst ranged from $4,895 to $6,250 per cubic meter.

- PNM's power costs are much higher than the Cost Manual estimate.
- Although modern SCR systems are typically designed to achieve 90+% NO_x reductions, we assumed a 0.05 lb/mmBtu (an 83% reduction) "target" for SCR based upon the performance of the boiler retrofits discussed above.
- The Total Capital Investment would be approximately $392 million.
- The Incremental Annual Cost for adding SCR to remove over 17,000 tons/yr more NO_X would be $45 million or less than $2,600/ton.

Step 5 of the BART Analysis: Visibility Impacts Analysis of Remaining Control Technologies

Because the modeling analysis conducted by EPA is superior to that conducted by PNM, we are commenting only upon how the results of the EPA analyses can be interpreted in the context of the effectiveness of SCR at SJGS.

EPA modeled a revised baseline scenario to incorporate the proposed lower SO2 emission rate of 0.15 lb/mmBtu rather than the 0.18 lb/mmBtu included in the original post-consent decree baseline modeled by NMED. The purpose of this was to separate any visibility benefit from lowering the SO2 emission rate from the benefit received from the operation of the SCR.

Modeling Results--Visibility Improvement from Operation of SCR
EPA: "Modeled impacts on the Class I areas of SJGS are shown in Table 6-6. The table shows the maximum of the 98th percentile daily delta deciview impacts from the three modeled years using the default background ammonia concentration of 1 ppb and Method 8 to calculate visibility. ...Visibility improvement due to installation of SCR is significant, including a 3.11 dv improvement at Canyonlands and 2.88 dv at Mesa Verde. Total deciview improvement at all Class I areas within 300km of the facility is 21.69 dv, a decrease in visibility impairment of 65% from the revised baseline..."

EPA Table 6-6. EPA Modeling Results – Impacts of SJGS on Visibility (maximum of 98th Percentile of daily maximum dv of 2001, 2002, and 2003) at Sixteen Class I Areas (1ppb background ammonia concentration, Method 8)

Class I Area	Distance to SJGS (km)	Visibility Impact (dv) after applying: Revised Baseline	SCR	SCR visibility improvement over revised baseline (dv)
Arches	222	3.50	1.12	2.38
Bandelier Wilderness	210	1.39	0.48	0.91
Black Canyon of the Gunnison Wilderness	203	1.41	0.42	0.99
Canyonlands	170	4.64	1.53	3.11
Capitol Reef	232	2.38	0.82	1.56
La Garita Wilderness	169	1.93	0.57	1.36
Grand Canyon	285	0.93	0.33	0.60
Great Sand Dunes National Monument	269	1.53	0.49	1.04
Mesa Verde	40	5.15	2.27	2.88
Pecos Wilderness	248	1.27	0.47	0.80
Petrified Forest	213	0.52	0.21	0.31
San Pedro Parks Wilderness	155	2.20	0.74	1.46
Maroon Bells Snowmass Wilderness	271	0.70	0.28	0.42
West Elk Wilderness	216	1.59	0.45	1.14
Weminuche Wilderness	98	2.92	0.87	2.05
Wheeler Peak Wilderness	258	1.12	0.44	0.68
Total Delta dv		33.18	11.48	21.69

NPS: Modeling results for the addition of SCR indicate that this option would reduce cumulative impacts by 21.69 dv with a 2.88 dv improvement at Mesa Verde NP (40 km away), with an even greater improvement predicted at Canyonlands NP (170 km away). We have observed in our analysis of impacts of the Navajo Generating Station (NGS) upon Grand Canyon National Park 20 km away that time (and, therefore, distance) is required for transformation of NO_X to visibility-impairing particulates. When we modeled impacts further into the Grand Canyon from NGS, we found that the benefits of reducing NO_X increased with distance, up to a point. The same effect may be occurring with SJGS, and modeling of more-distant receptors in Mesa Verde NP may yield even greater improvements.

Visibility Improvement Metrics

We support EPA in reporting the cumulative visibility impacts of SJGS and the benefits of SCR at the 16 Class I areas on the Colorado Plateau (EPA Table 6.7). We continue to believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a

BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas.

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. For example, we understand that the Oregon Department of Environmental Quality used a similar approach in its analyses when it evaluated the benefits of various control strategies on all 14 of the Class I areas within 300 km of the Boardman power plant. Cumulative benefits have been a factor in the BART determinations by NM, OR, and WY, as well as EPA in its proposals for the Navajo Generating Station and the Four Corners Power Plant. And, EPA, in its analysis supporting its determination that CAIR is better-than-BART simply summed dv impacts across many Class I areas of varying sizes in order to generate average visibility impact estimates.

NOx BART Determination

Cost-Effectiveness Metrics

In addition to the $/ton metric, we recommend that EPA evaluate the visibility metric $/deciview (dv) as an additional tool to report the benefits of emissions controls. BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. For example, Oregon DEQ has established a cost/ton threshold of $7,300 based upon the premise that improving visibility in multiple Class I areas warrants a higher cost/ton than where only one Class I area is affected. In their BART proposal for SJGS, New Mexico used a range from $5,946/ton to $7,398/ton. Colorado uses $5,000/ton, New York uses $5,500/ton, and Wisconsin is using $7,000 - $10,000/ton as its BART threshold.[31] EPA has proposed SCR at the Four Corners Power Plant at $2,600 - $2,900/ton, and at SJGS at $1,600-1,900/ton.

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. We believe that visibility improvement must be a critical factor in any program designed to improve visibility. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[32] of BART analyses across the U.S. reveals that the average cost per dv proposed by

[31] "The Department used cost-per-ton reduced as the primary metric for determining the BART level of control. The upper limit for this metric was $7,000 to $10,000 per ton, which reflects historical low-end costs for controls required under BACT." BEST AVAILABLE RETROFIT TECHNOLOGY AT NON-EGU FACILITIES April 19, 2010, WISCONSIN DEPARTMENT OF NATURAL RESOURCES

[32] http://www.wrapair.org/forums/ssjf/bart.html

either a state or a BART source is \$14 - \$18 million,[33] with a maximum of \$51 million per dv proposed by South Dakota at the Big Stone power plant. (For example, we note that OR DEQ has explicitly chosen \$10 million/dv as a cost criterion, which is somewhat below the national average.)

When we combine our cost estimates for SCR with the visibility improvement estimated by EPA, we find that SCR costing \$45 million/yr would yield a 3.11 dv improvement at Canyonlands NP for a cost-effectiveness there of \$14.5 million/dv and a cumulative improvement of 21.69 dv for a cumulative cost-effectiveness of \$2.1 million/dv. Because both the individual and the cumulative cost-effectiveness of SCR are within (or below) the range of costs accepted by other states (and EPA), SCR is clearly cost-effective at SJGS.

Conclusions & Recommendations

We have shown that PNM has underestimated the ability of SCR to reduce emissions, and presented real-world emission data showing examples of coal-fired EGU retrofits meeting 0.05 lb/mmBtu (or lower) on an annual basis. We have also shown that Black & Veatch, the consultant that prepared the SJGS estimates, assumed that SCR could achieve 0.05 lb/mmBtu (annual average) when evaluating retrofitting of SCR at the Craig power plant. (And, Salt River Project has used a 0.05 lb/mmBtu annual average in its SCR retrofit analysis for the Navajo Generating Station.) While it is easy to find coal-fired SCR retrofits that are emitting at higher rates, we believe that we should be basing decisions upon what the current state-of-the-art can do,[34] and SCR can achieve 0.05 lb/mmBtu or lower on an annual average at SJGS.

We have also provided evidence indicating that PNM has overestimated SCR costs. The Black & Veatch approach used by PNM is neither transparent nor does it follow the methods described in the EPA Control Cost Manual. Instead, the B&V approach includes costs which are not appropriate, and the results are consistently higher than real-world industry data would suggest are appropriate for SJGS (or any other power plant).

We commend EPA for the thoroughness and the critical approach of its analysis. We have provided additional data from EPA's Clean Air Markets Database showing that SCR can achieve lower NO_X emission rates on an annual basis than used by PNM in its analyses, which supports EPA's concern that PNM has underestimated the benefits of adding SCR. We have also provided SCR cost information from industry sources and publications that indicate that PNM's estimates of the costs of adding SCR at SJGS would exceed any costs actually experienced at an EGU in the US. We have also provided information, based upon EPA's OAQPS Control Cost Manual, that indicates that PNM has overestimated its annual costs to operate and maintain SCRs at SJGS. This supports EPA's concern that PNM has overestimated the cost of installing and operating SCR.

[33] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at \$580,000 per day and \$18.5 million per deciview."

[34] In its 10/26/10 letter to CDPHE, EPA advised that "many boilers retrofitted with SCR are achieving an emission rate of 0.03 – 0.06 lb/mmBtu" and that the state should take current emission rates into consideration.

We estimate that addition of SCR to SJGS Units #1 - #4 represents BART because it would result in cost-effectiveness values that fall within the $14 million - $20 million **average** cost/deciview proposed as BART by other sources and states.

We conclude that SCR at 0.05 lb/mmBtu (30-day rolling average) represents BART for SJGS.